CELTIC EXPLORATION LTD.

2009 ANNUAL REPORT

while some see a recession, we see an opportunity for innovation. while others are guided by market price, we are led by a relentless dedication to increase value.

WHEN SOME ARE STALLED, WE ARE DRIVEN BY FORESIGHT, BOLD IDEAS AND DETERMINATION.

Since the founding of Celtic Exploration in 2002, we have built a company that will flourish in today's environment of constant change: a company that has been adept at expanding production, maintaining a strong asset base and increasing shareholder value.

WE SEE OPPORTUNITIES WHEN OTHERS SEE CHALLENGES.

WE SEE THE CELTIC WAY.

FINANCIAL ACUMEN

Celtic uses its financial management experience to thrive in favourable market conditions and to stand above the crowd in unfavourable ones.

FINANCIAL ACUMEN

NET ASSET VALUE PER SHARE
AT DECEMBER 31, 2009
$19.76

BANK CREDIT FACILITY
IN MILLIONS
$215.0

FINANCIAL ACUMEN

Celtic historically maintains a strong financial position through its use of equity when necessary and prudent use of bank debt. In addition, Celtic has benefitted significantly through the use of risk management financial instruments and by taking full advantage of government sponsored incentive programs.

The economic environment in 2009 was a difficult one with recession conditions, tight credit markets, limited access to new capital and low oil and gas prices. Celtic was able to overcome these conditions. In 2009, Celtic completed an equity issue for gross proceeds of $36.4 million; increased the authorized borrowing limit on our credit facility by $15.0 million to 215.0 million; realized $34.3 million in hedging gains; earned $20.6 million in drilling royalty credits and we reduced our corporate royalty rate to 13.3% compared to 22.2% in 2008 by taking full advantage of Alberta's new royalty incentive programs.

INCREASING SHAREHOLDER VALUE
NET ASSET VALUE ($/PER SHARE)

2002
2.16

2003
3.81

2004
5.55

2005
11.53

2006
12.25

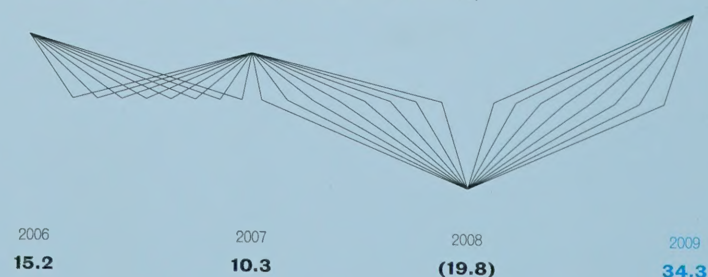
2007
11.80

2008
18.97

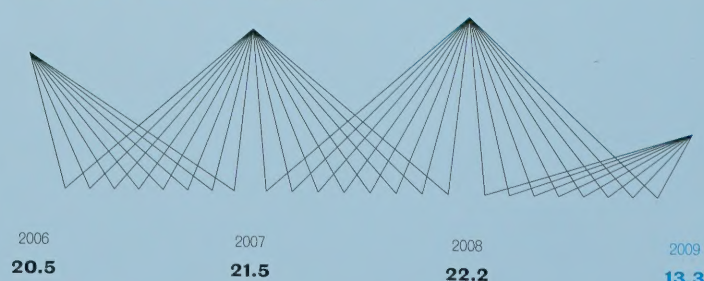
2009
19.76

2002 TO 2009
915%
GROWTH

HEDGING STRATEGY IN ACTION
REALIZED HEDGING GAINS (LOSSES) ($ MILLIONS)



IMPACT OF THE ALBERTA ROYALTY INCENTIVE PROGRAM
CORPORATE ROYALTY RATES (%)



NET DEBT OUTSTANDING IN MILLIONS AT DECEMBER 31, 2009

$168.4

FUNDS FROM OPERATIONS IN MILLIONS GENERATED IN 2009

$118.0

OPERATING NETBACK PER BOE IN 2009

$25.00

HIGHLIGHTS *($ 000's, unless otherwise indicated)*	Three months ended December 31 **2009**	2008	Change	Year ended December 31 **2009**	2008	Change
FINANCIAL						
Revenue, before royalties and financial instruments	**60,146**	51,842	16%	**172,613**	263,337	-34%
Funds from operations	**42,003**	32,049	31%	**118,025**	131,360	-10%
Basic *($/share)*	**0.94**	0.78	21%	**2.72**	3.28	-17%
Diluted *($/share)*	**0.93**	0.78	19%	**2.70**	3.27	-17%
Net earnings (loss)	**906**	29,585	-	**(23,258)**	44,239	-
Basic *($/share)*	**0.02**	0.72	-	**(0.54)**	1.10	-
Diluted *($/share)*	**0.02**	0.72	-	**(0.54)**	1.10	-
Capital expenditures, net of dispositions and drilling credits	**41,519**	42,774	-3%	**148,761**	183,477	-19%
Total assets				**678,770**	649,654	4%
Bank debt, net of working capital				**168,417**	136,595	23%
Bank debt, net of working capital, excluding non-cash financial instruments				**168,209**	160,187	5%
Shareholders' equity				**387,190**	367,808	5%
Weighted average common shares outstanding *(thousands)*						
Basic	**44,540**	41,207	8%	**43,414**	40,047	8%
Diluted	**45,332**	41,264	10%	**43,750**	40,141	9%

	Three months ended December 31 **2009**	2008	Change	Year ended December 31 **2009**	2008	Change
OPERATIONS						
Production						
Oil *(bbls/d)*	**4,384**	3,554	23%	**3,687**	3,404	8%
Gas *(mcf/d)*	**77,339**	51,029	52%	**63,028**	46,000	37%
Combined *(BOE/d)*	**17,274**	12,059	43%	**14,192**	11,071	28%
Production per million shares *(BOE/d)*	**388**	293	32%	**327**	276	18%
Realized sales prices, after financial instruments						
Oil *($/bbl)*	**80.22**	68.63	17%	**81.00**	82.45	-2%
Gas *($/mcf)*	**4.86**	7.36	-34%	**4.36**	8.37	-48%
Operating netbacks *($/BOE)*						
Oil and gas revenue	**37.85**	46.73	-19%	**33.33**	65.00	-49%
Realized gain (loss) on financial instruments	**4.32**	4.57		**7.10**	(4.88)	
Realized sales price, after financial instruments	**42.17**	51.30	-18%	**40.43**	60.12	-33%
Royalties	**(3.21)**	(9.71)	-67%	**(4.43)**	(14.42)	-69%
Production expense	**(9.75)**	(9.96)	-2%	**(10.26)**	(10.21)	0%
Transportation expense	**(0.79)**	(0.60)	32%	**(0.74)**	(0.57)	30%
Operating netback	**28.42**	31.03	-8%	**25.00**	34.92	-28%
Drilling activity						
Total wells	**17**	14	21%	**55**	54	2%
Working interest wells	**9.6**	10.2	-6%	**43.0**	41.1	5%
Success rate on working interest wells	**100%**	100%	0%	**91%**	88%	3%
Undeveloped land						
Gross acres				**363,473**	318,969	14%
Net acres				**294,700**	246,629	19%
Reserves						
Oil *(mbbls)*				**15,042**	14,372	5%
Gas *(mmcf)*				**272,236**	235,353	16%
Combined *(mBOE)*				**60,415**	53,598	13%
Finding, development & acquisition cost						
Proved *($/BOE)*				**12.89**	19.43	-34%
Proved plus probable *($/BOE)*				**9.84**	12.24	-20%
Recycle ratio - proved plus probable				**2.5**	2.9	-14%
Net asset value, discounted at 10%, before tax *($/share)*				**19.76**	18.97	4%

Use our experience to manage our business in a prudent manner so that we thrive in favourable market conditions and we stand above the crowd in unfavourable market conditions.

RESOURCE PLAYS

RESOURCE
PLAYS

With its experience of establishing resource plays at Kaybob, Celtic will use its knowledge to develop new resource plays in other areas in west central Alberta.

ACRES OF UNDEVELOPED LAND AT DECEMBER 31, 2009

294,700

GROSS WELLS DRILLED IN 2009

55

DRILLING SUCCESS RATE IN 2009

91%

PERCENTAGE INCREASE IN PROVED RESERVES IN 2009

21%

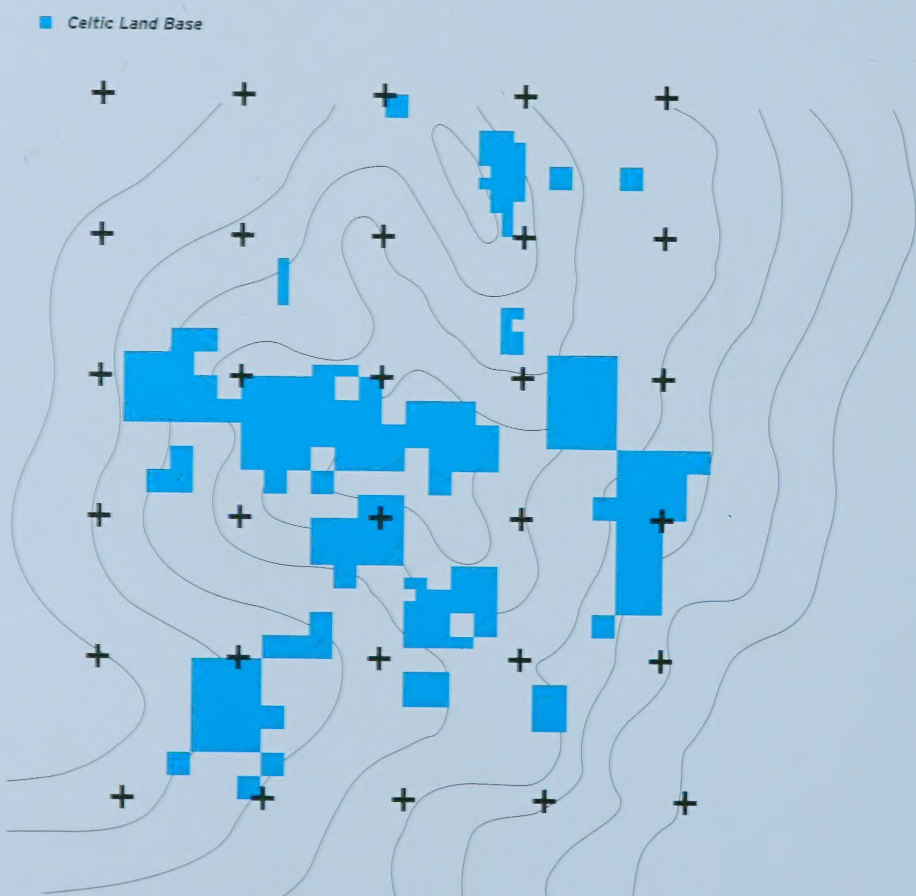
2P FD&A COST PER BOE IN 2009

$9.84

2P RECYCLE RATIO IN 2009

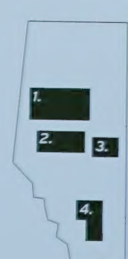
2.5 X

RESOURCE PLAYS



KAYBOB – TRIASSIC MONTNEY

Celtic has actively been developing the Triassic Montney resource play at Kaybob with horizontal drilling. Initial wells were completed with 5 to 7 multi-stage fractures. However, more recently, the Company has been completing wells with 11 to 16 multi-stage fractures. Average initial production rates have averaged 8.0 MMCF per day and average estimated ultimate recoverable reserves are 495,000 BOE per horizontal well. The Montney at Kaybob is liquids-rich with yields of approximately 26 BBLS per MMCF.



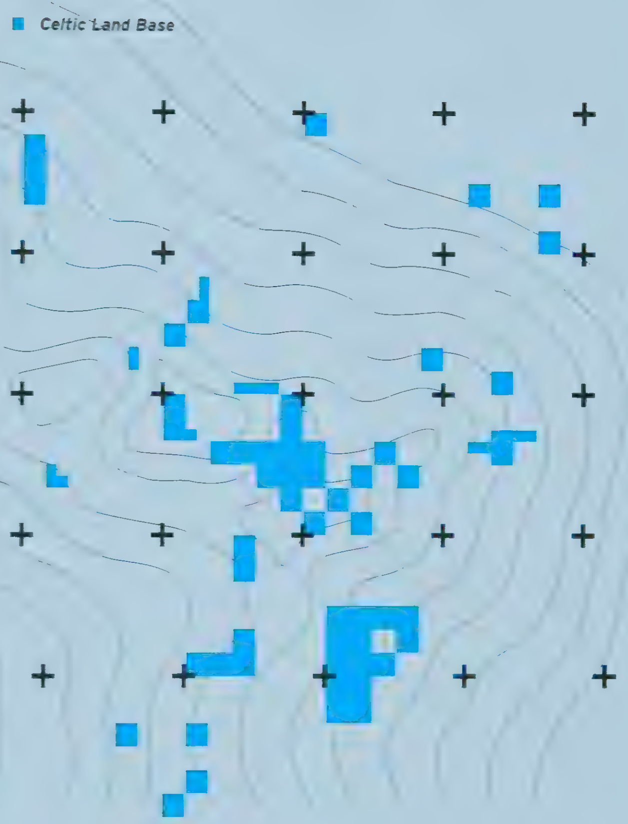
QUALITY ASSETS

CORE AREAS

1. *northern alberta*
2. *west central alberta*
3. *east central alberta*
4. *southern alberta*

KAYBOB – CRETACEOUS

Celtic began developing the Cretaceous Bluesky and Notikewin resource plays at Kaybob with horizontal drilling and multi-stage fracture completions in 2009. To date, in the Bluesky, average initial production rates have averaged 9.0 MMCF per day and average estimated ultimate recoverable reserves are 668,000 BOE per horizontal well. The Bluesky at Kaybob is liquids-rich with yields of approximately 40 BBLS per MMCF.



Resource plays have changed the landscape of the Western Canadian Sedimentary Basin which was previously viewed as mature with limited growth opportunities.

Horizontal drilling techniques with completions using multi-stage fractures have created opportunities to unlock significant hydrocarbon reservoirs that were previously inaccessible.

Celtic has been a leader using horizontal drilling with multi-stage completions at Kaybob in the Triassic Montney and Cretaceous Bluesky and Notikewin formations. In 2010, Celtic expects to explore in other areas with similar formation characteristics applying the technology used at Kaybob with the objective of ultimately adding new resource plays to the Company's asset base.

After drilling numerous wells, Celtic has gained sufficient experience to drill in the most efficient manner, reducing capital costs, ultimately leading to lower finding costs. Examples are the use of multi-pad drilling locations and mono-bore drilling techniques.

Celtic's Montney and Bluesky prospects at Kaybob would have been categorized as conventional reservoirs in the past, however new technology allows the Company to provide repeatable drilling results and higher recovery rates of gas-in-place, ultimately leading to long-life production categorized as resource plays.

NATURAL GAS

In 2010, industrial demand for natural gas in North America is expected to increase with a recovering economy, while at the same time, natural gas supply may shrink given lower rig utilization. Both of these factors will likely result in higher natural gas prices in 2010 compared to 2009.

NATURAL GAS

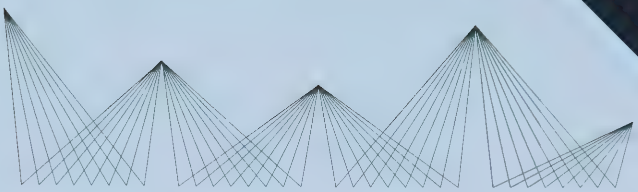
Recent growth in natural gas supply has come from unconventional sources – natural gas from reservoir rocks that are less porous and permeable than conventional reservoirs. Unconventional gas does not readily flow to the well bore in the same manner as conventional gas.

Examples of unconventional gas reservoirs include tight sands, gas shales and coalbeds. Advanced technologies, such as horizontal drilling, hydraulic fracturing and multi-lateral well bores have made it possible to unlock these reservoirs. Due to the nature of unconventional reservoirs, recent increases in natural gas supply with record rig utilization in the U.S. peaking in 2008, the overall decline rate of U.S. production will likely increase, as typical unconventional gas wells produce a larger portion of their estimated ultimate recoverable reserves in the first year.

CELTIC'S AVERAGE DAILY GAS PRODUCTION IN 2009 (MCF PER DAY)
63,028

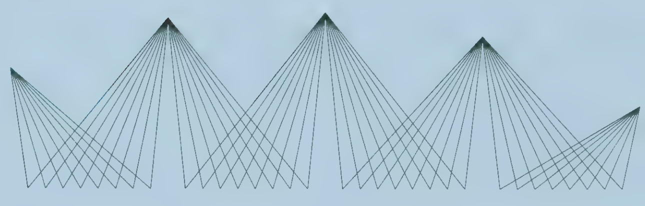
CELTIC'S P+P GAS RESERVES AT DECEMBER 31, 2009 (MCF)
272,236,000

CELTIC'S AVERAGE GAS ROYALTY RATE IN 2009
9%



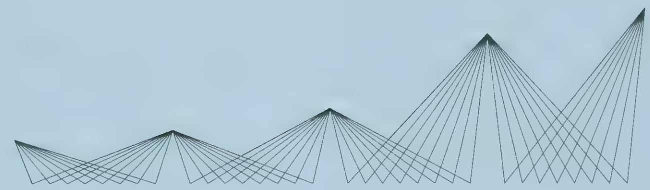
HISTORICAL NATURAL GAS PRICES
ALBERTA AECO-C AVERAGE SPOT PRICES ($/GJ):

2005	2006	2007	2008	2009
8.14	6.79	6.31	7.73	3.97



DECLINING RIG UTILIZATION IN 2009
US GAS ROTARY RIG COUNT AT DECEMBER 31:

2005	2006	2007	2008	
1,234	1,425	1,452	1,347	759



NATURAL GAS SUPPLY
US DRY GAS PRODUCTION (BCF PER DAY):

2005	2006	2007	2008	2009
49.5	50.7	52.3	55.8	57.7

NORTH AMERICAN NATURAL GAS BASINS – ABUNDANT AND WIDESPREAD DRILLING TECHNOLOGY

Natural gas is a cleaner burning energy source than most alternatives available today and will likely become the energy of choice in the future as global leaders around the world have made the environment and climate change a high priority. Large deposits of natural gas in basins widespread across North America are further being enhanced with new technology providing access to shale reservoirs that were previously not commercially viable.

Natural Gas Basin
Shale Gas Play

With higher decline rates on existing production in North America, the supply and demand picture could become tight with the return of industrial demand for gas that follows an economic recovery. Furthermore, to date in 2010, the northern hemisphere has experienced frigid winter conditions with below normal temperatures that have resulted in lower natural gas storage levels which had recently been at record high levels.

Celtic is optimistic that in the long-term unconventional sources of natural gas will provide a reliable supply to North America's growing independence on this cleaner burning source of energy. However, until rig utilization increases, in the short-term, the supply and demand picture will remain tight, leading to higher natural gas prices in the second half of 2010.

Looking ahead to 2010, Celtic will use its knowledge and experience with horizontal drilling and multi-stage fracture completion technology to develop its existing land base.

DRILLING TECHNOLOGY

ALBERTA FORMATIONS

Celtic's development activity in 2009 was focused at Kaybob, Alberta where the Company targets liquids-rich natural gas in multi-zone formations. The Company has added production and reserves from the Triassic Montney, Jurassic Nordegg, Cretaceous Bluesky and Cretaceous Notikewin formations. Development in these formations is expected to continue in future years at Kaybob. The Company has also assembled exploration acreage in other areas in formations with similar characteristics that Celtic plans to test with new drilling in 2010.

PROVED PLUS PROBABLE RESERVES AT DECEMBER 31, 2009 (BOE)

60,415,000

DRILLING TECHNOLOGY

AVERAGE DAILY PRODUCTION IN Q4 2009 (BOE PER DAY)

17,274

2P FD&A COST PER BOE IN 2009

$9.84

GROSS WELLS DRILLED IN 2009

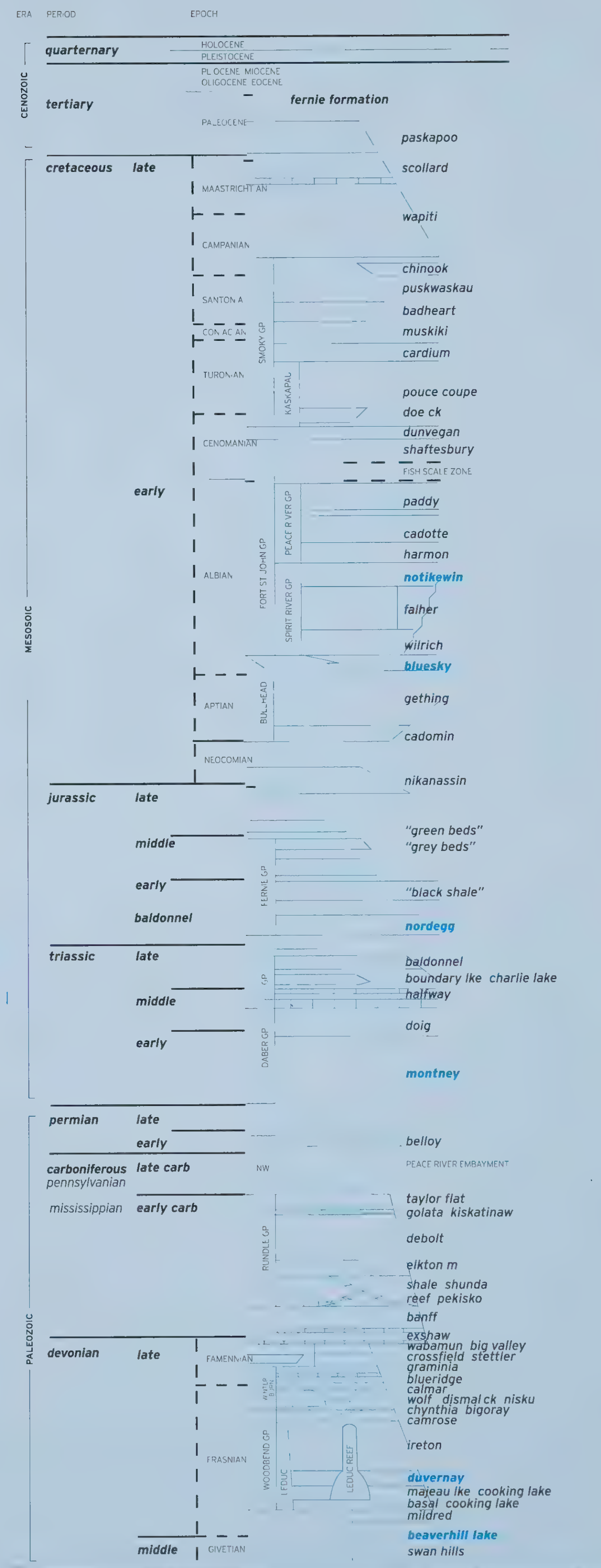
55

2P RECYCLE RATIO IN 2009

2.5 X

ACRES OF UNDEVELOPED LAND AT DECEMBER 31, 2009

294,700



In 2009, Celtic drilled 40 horizontal wells at Kaybob, Alberta. 27 were drilled into the Triassic Montney formation, 10 were drilled into the Cretaceous Bluesky formation and 2 were Cretaceous Notikewin wells.

The Company has been using multi-stage fracturing completion techniques on its horizontal wells. In 2009, 32 wells were completed with 11 or more fractures and 8 wells were completed with less than 11 fractures. This technology allows the Company to access gas reservoirs in tight sands with significantly better economics compared to vertical wells in the same formation.

HORIZONTAL DRILLING

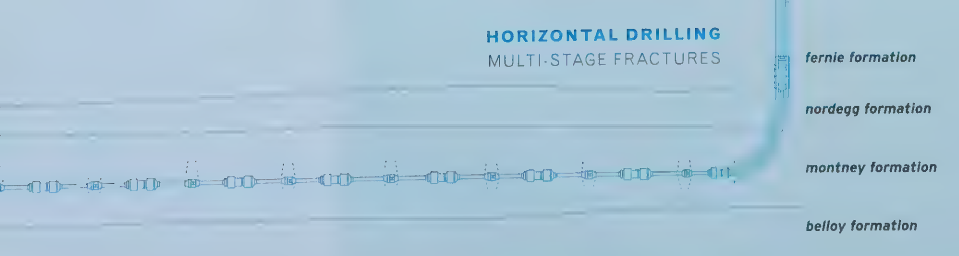
Horizontal drilling and the multi-stage fracing systems have allowed these tighter reserves to be accessed but in addition to this the fracing technology itself has been changing dramatically. Much larger fracs are being done with lower sand concentrations yielding very positive results. Although the fracs are larger they can be contained within smaller "windows" by using "slick water" or "slick oil". These fluids have very low viscosities allowing the frac to grow in length but not height.

MULTI-STAGE FRACTURING SYSTEMS

As well, new multi-stage fracturing systems have been developed and are yielding good results. Celtic plans to drill its first multi-leg/multi-frac well in 2010 accessing two different zones from the same wellbore.

MONOBORE SYSTEMS

Monobore systems allow wells to be drilled quicker using less production casing and cement. A monobore well is drilled from surface casing right to the end of the horizontal leg before setting production casing. This allows the step of setting intermediate casing to be skipped saving time and money. Some of Celtic's Cretaceous horizontals are drilled using monobores systems.



CLIMATE CHANGE

World leaders gathered in Copenhagen in December 2009 to discuss climate policy. Even though consensus was not achieved, the message from the Copenhagen Accord was clear: GHG and other air pollutants must be regulated in order to deal effectively with climate change.

CLIMATE CHANGE

ESTIMATED WORLD CO_2E EMISSIONS IN 2006 (TONNES)

28,000,000

ESTIMATED ALBERTA GAS PROCESSING FACILITIES EMISSIONS IN 2006 (TONNES)

8,500

Celtic has applied to the Energy Resources Conservation Board ("ERCB") to make modifications to its existing sour gas processing facility located at Kaybob. The Company believes that these modifications will result in significant reductions in GHG emissions and is confident that the ERCB will approve the Company's application. If approved, Celtic expects to spend approximately $35.0 million in capital expenditures that will result in gas processing capability of handling 150 MMCF per day of raw gas. In addition to reductions in GHG emissions, Celtic will benefit with lower overall processing costs for the majority of its natural gas production at Kaybob, Alberta.

PROVINCIAL PLAN

The Alberta Government has set targets for GHG emission reductions. Alberta Environment required all facilities that exceeded 100,000 tonnes of CO_2E to reduce their GHG emissions intensity by 12% versus an established baseline emissions intensity. In order to comply with the Alberta regulations, companies can make operating improvements to its facilities, purchase carbon offsets or make a monetary contribution to the Alberta Climate Change and Emissions Management Fund. As at December 31, 2009, none of the Celtic owned facilities have triggered the GHG reporting and reduction requirements.

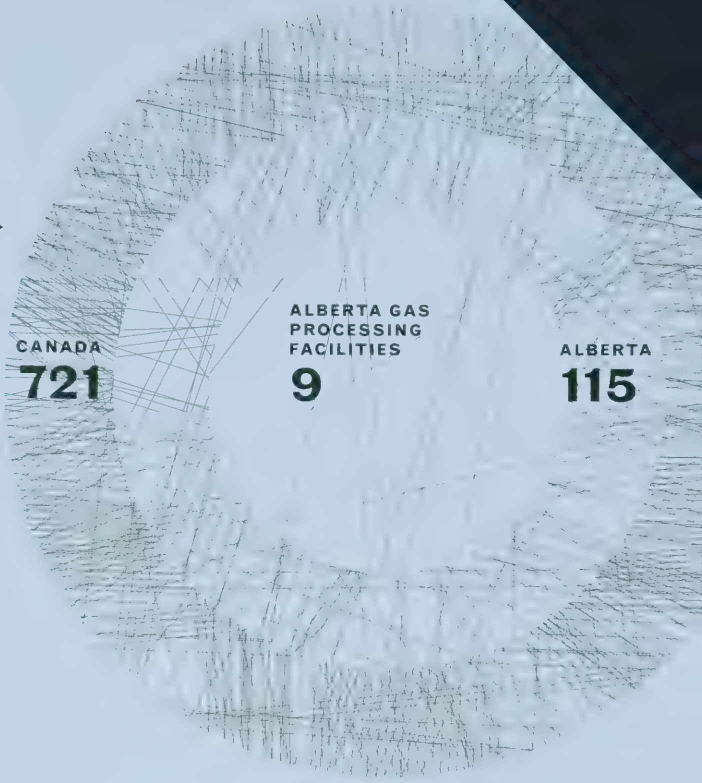
FEDERAL PLAN

The Federal Government has announced its intention to regulate GHG and other air pollutants. As these regulations are under development, the Company is unable to predict the total impact of the potential regulations upon its business.

CARBON DIOXIDE EQUIVALENT EMISSIONS (MT)

ALBERTA GAS PROCESSING FACILITIES ACCOUNT FOR 1% OF CARBON DIOXIDE EQUIVALENT EMISSIONS IN CANADA

1%

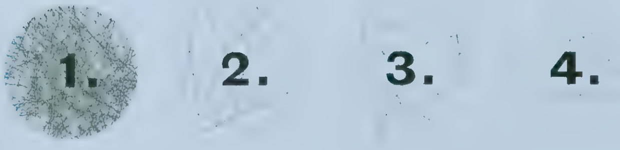


GREEN HOUSE GAS (GHG) EMISSIONS

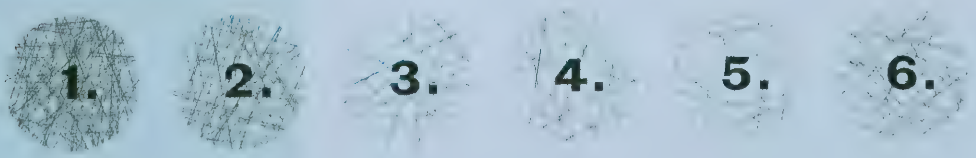
World leaders gathered in Copenhagen in December 2009 with Green House Gas (GHG) emissions and the impact to climate change a key discussion point. GHG emissions can be measured as carbon dioxide equivalents (CO_2E) and would consist of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride. In 2006 both Environment Canada and Alberta Environment required all industries to report GHG emission data from all facilities that emitted over 100,000 tonnes of CO_2E. The graph above shows the 2006 CO_2E emissions.

ALBERTA 2006 GHG EMISSIONS
BY GAS TYPE

1. CO_2 94%
2. CH_4 3%
3. N_2O 2%
4. other 1%



ALBERTA 2006 GHG EMISSIONS
BY FACILITY TYPE



1. power plants 45%
2. oil sands 21%
3. gas plants 7%
4. heavy oil 7%
5. chemical plants 6%
6. other 14%

STRATEGIC EXPERTISE

Left to right
Alan Franks, Michael Shea, Sadiq Lalani, David Wilson, Robert Dales, Neil Sinclair, Eldon McIntyre, William Guinan, David Morgenstern (not pictured)

STRATEGIC EXPERTISE

BOARD OF DIRECTORS AND MANAGEMENT TEAM

Robert J. Dales
Chairman of the Audit Committee
Member of the Compensation Committee
Member of the Reserves Committee

Mr. Dales has over 30 years of experience in the oil and gas industry. He is currently the President and Chief Executive Officer and a director of Desco Resources Inc., a capital pool company, and President and a director of Valhalla Ventures Inc., a private investment company based in Calgary, Alberta. From 1981 to 1999, Mr. Dales worked at PANARTIC Oils Ltd. Mr. Dales was President, Chief Executive Officer and a director of Resolution Energy Inc., a public company from June 1993 to October 2001. From 1994 to 1996, Mr. Dales was Secretary-Treasurer and a director of Energy North Inc., a public company. Mr. Dales was also President and a director Desco Resources Ltd. from March 1997 until October 1998. Mr. Dales currently serves as a director and officer of a number of public and private companies. Mr. Dales holds a Bachelor of Commerce degree from the University of Calgary and a Master of Business Administration from the University of Alberta.

William C. Guinan
Chairman of the Board and Corporate Secretary
Chairman of the Disclosure Committee

Mr. Guinan is a partner at the law firm of Borden Ladner Gervais LLP, Calgary, Alberta. Mr. Guinan specializes in banking, oil and gas and securities law with a focus on both private and public equity offerings and mergers and acquisitions. Mr. Guinan currently serves as a director and officer of a number of public and private companies. Mr. Guinan received a Bachelor of Business Administration degree from Acadia University in 1977 and a Master of Business Administration and Bachelor of Laws degree from Dalhousie University in 1982.

Neil G. Sinclair
Chairman of the Compensation Committee
Member of the Audit Committee
Member of the Disclosure Committee

Mr. Sinclair has been the President of Sinson Investments Ltd., an active private corporation with significant real estate operations in British Columbia, for over 30 years. Mr. Sinclair received a Bachelors of Arts from the University of Victoria in 1969 and a Master of Business Administration from the University of Western Ontario in 1971. Mr. Sinclair currently serves as an officer for a number of public and private companies.

Eldon A. McIntyre
Chairman of the Reserves Committee
Member of the Audit Committee
Member of the Compensation Committee

Mr. McIntyre has over 40 years of experience in the oil and gas industry. He was the Vice President and a director of Strike Energy Inc., a Toronto Stock Exchange listed company, from 1988 to 1994. Mr. McIntyre was also a director of Genesis Exploration Ltd., from 1992 until May, 2001. He is also the sole director and shareholder of Jarrod Oils Ltd., a private oil and gas company he founded in the late 1970's, which holds various interests in oil and gas properties located in western Canada.

David J. Wilson
President and Chief Executive Officer
Member of the Reserves Committee
Member of the Disclosure Committee
Member of the Board of Directors

Mr. Wilson has over 25 years of experience in the oil and gas industry. He was the sole director and shareholder of Pronghorn Resources Ltd., a private oil and gas company he founded in 1987. Mr. Wilson was President and Chief Executive Officer of Genesis Exploration Ltd. from 1992 to May 2001. Mr. Wilson was President of Vintage Petroleum Canada, Inc. from May 2001 to May 2002. He became President and Chief Executive Officer of Celtic in September 2002. Mr. Wilson holds an honours diploma in Petroleum Technology from the Southern Alberta Institute of Technology.

Celtic's Board of Directors is responsible for stewardship of the company; supervising the management of the business and affairs of the company; and providing leadership to the company by practicing responsible, sustainable and ethical decision making. In carrying out its mandate, Celtic's Board has the responsibility to act honestly and in good faith with a view to the best interests of the company; exercise the care, diligence and skill that a reasonably prudent Board would exercise in comparable circumstances; and direct management to ensure legal, regulatory and exchange requirements applicable to the company have been met.

Sadiq H. Lalani
Vice President, Finance and Chief Financial Officer

Mr. Lalani has over 24 years of experience in the oil and gas industry. From January 1986 to April 1996, he worked at Morgan Hydrocarbons Inc. Mr. Lalani was Senior Vice President and Chief Financial Officer of Triumph Energy Corporation from April 1996 to May 2001. He was Vice President, Finance and Chief Financial Officer of True Energy Inc. from October 2001 to October 2002. He became Vice President, Finance and Chief Financial Officer of Celtic in October 2002. Mr. Lalani holds a Bachelor of Commerce degree from the University of Calgary.

Alan G. Franks
Vice President, Operations

Mr. Franks has over 27 years of experience in the oil and gas industry. From 1985 to 1995, he worked at Cube Energy Corp. Mr. Franks was Manager, Operations of Cirque Energy Corp. and Cirque Energy (UK) Limited from 1998 to May 2001. He was Project Manager, Facilities at Canadian Natural Resources Limited from May 2001 to December 2002. He became Vice President, Operations of Celtic in December 2002. Mr. Franks holds a Bachelor of Science degree from the University of Wyoming.

Michael R. Shea
Vice President, Land

Mr. Shea has over 29 years of experience in the oil and gas industry. From 1980 to 1991 he worked with Texaco Canada Resources Limited and then subsequently with Esso Resources Canada Limited. In 1991 Mr. Shea joined Texaco Canada Petroleum Inc., as Land Manager, and from 1993 to 1997 he was Vice President of Asset Management. From May 1997 to February 1999, Mr. Shea was Land Manager at Newquest Energy Inc. Mr. Shea was a Founder, President and Chief Executive Officer of Canadian Mustang Energy Inc. from April 1999 to June 2001. He was a Land Consultant at NCE Resources Group from September 2001 to December 2002. He became Vice President, Land of Celtic in December 2002. Mr. Shea holds a Bachelor of Science degree (with Distinction) from the University of Alberta.

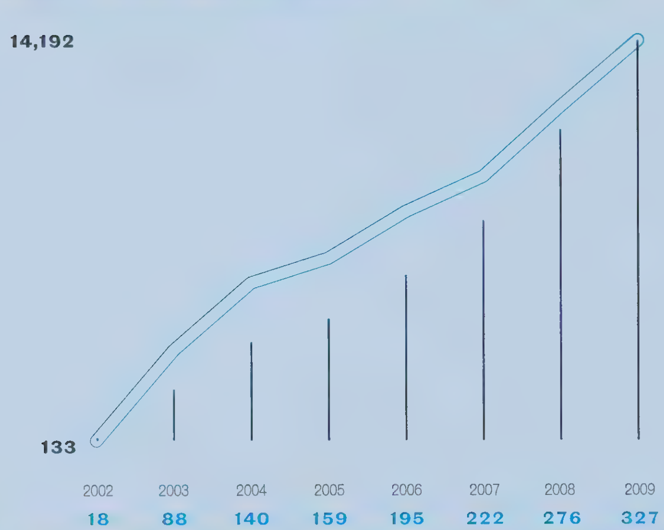
David C. Morgenstern
Vice President, Exploration

Mr. Morgenstern has over 30 years of experience in the oil and gas industry. From 1995 to 1996, he worked at Clarinet Resources Ltd. Mr. Morgenstern was President and Chief Operating Officer of Symmetry Resources Inc. from June 1996 to February 2000. He was Senior Exploration Geologist at Vintage Petroleum Canada, Inc. from July 2001 to December 2004. He became Vice President, Exploration of Celtic in December 2004. Mr. Morgenstern holds a Bachelor of Science degree from the University of Alberta.

PERFORMANCE MEASURES

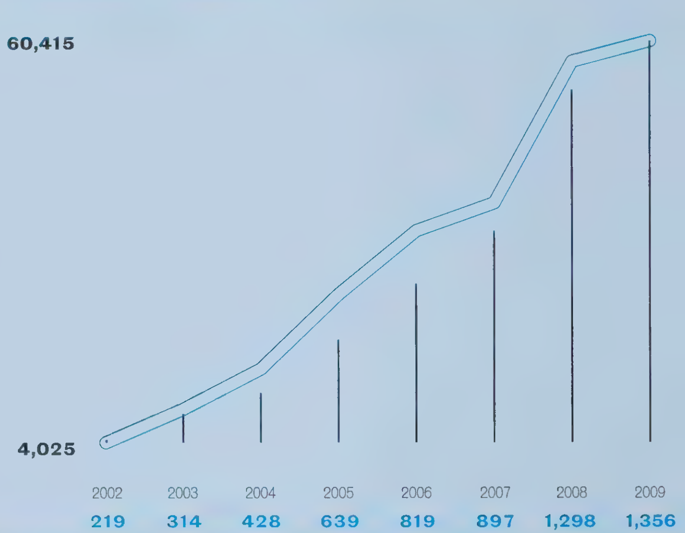
IMPROVED PROFITABILITY

PRODUCTION GROWTH



OPERATIONAL EXCELLENCE

RESERVES GROWTH



39%

24%

631%

17,274

40%

28%

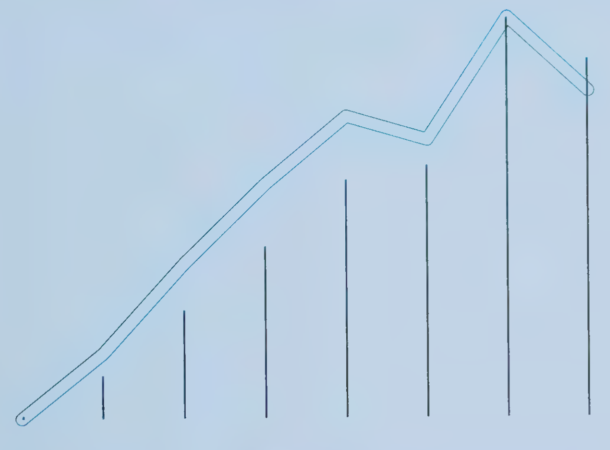
647%

$1,011,900,000

MAINTAINING CONFIDENCE

FUNDS FROM OPERATIONS GROWTH

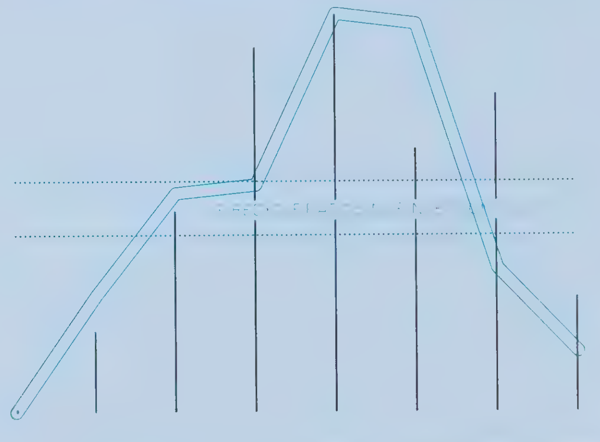
FFO PER SHARE (DILUTED) FFO ($M)



RESPONSIBLE GROWTH

RECYCLE RATIO

2P FD&A COST ($/BOE) OPERATING NETBACK ($/BOE)



41% **26%** **671%**

[illegible] Celtic's first full calendar year of operations in 2003, funds from [illegible] ("FFO") has grown at a CAGR of 41% from $15.3 million to $118.0 million in 2009. On a per share basis, production has [illegible] CAGR of 24% from 2003 to 2009. In the fourth quarter of [illegible] FFO was $42.0 million or $168.0 million annualized.

[illegible] guidance for 2010 the Company is forecasting FFO of $170.5 [illegible] or $3.74 per share diluted. This would represent increases of 44% [illegible] 39%, respectively, compared to 2009

$9.84 **$25.00** **2.5 X**

In 2009, Celtic added 12.0 million BOE of reserves resulting in a finding, development and acquisition ("FD&A") cost of $9.84 per BOE, including future development capital ("FDC") costs. With an operating netback of $25.00 per BOE, the Company's recycle ratio in 2009 was 2.5 times.

Since inception in September 2002, Celtic's FD&A has averaged $13.88 per BOE including FDC costs and operating netback has averaged [illegible] per BOE over the same period, resulting in a recycle ratio of [illegible]

ADDING SHAREHOLDER VALUE

1. *CAGR in Production per Share 24%*
2. *CAGR in Funds from Operations per Share 26%*
3. *CAGR in Reserves per Share 28%*

24% **26%** **28%**

PRESIDENT'S MESSAGE

Celtic Exploration Ltd. ("Celtic" or the "Company") is pleased to report to shareholders on the Company's activities. Once again, Celtic achieved superior operating results in 2009, not withstanding a significant downturn in the Canadian and global economies. The Company reported record production and reserves for the year and at the same time retained financial flexibility by maintaining a strong balance sheet.

Highlights of 2009 results include funds from operations of $118.0 million ($2.70 per share, diluted), net capital expenditures of $148.8 million, record production of 14,192 BOE per day, increased reserves of 60.4 million BOE, lower finding and development costs of $9.84 per BOE for proved plus probable reserves and a prudent financial position with debt, net of working capital, of $168.4 million or 1.0 times annualized fourth quarter 2009 funds from operations.

With its strong hedge position and with Alberta's new royalty incentive programs that took effect on April 1, 2009, Celtic embarked on an active drilling program commencing on April 1, 2009. The incentive programs which are in place until March 31, 2011, provide the company with lower royalty rates and drilling royalty credits. Ultimately, the royalty reduction and drilling credits combined will result in savings to the company in excess of half of total drilling expenditures.

The Company continued to expand its development potential in the Triassic Montney play in Celtic's most active operating area, Kaybob, Alberta. In addition, the Company also began drilling Cretaceous Bluesky and Notikewin prospects at Kaybob with encouraging results.

Celtic efficiently allocated the majority of its 2009 capital program to its Kaybob Montney, Bluesky and Notikewin development prospects. As a result, the Company has positioned itself to reap substantial rewards from drilling repeatable high productivity horizontal wells with multi-fracture completion technology allowing it to develop its large hydrocarbon resources in an economic manner.

Celtic employs horizontal drilling with multi-stage fracture completion techniques with high rates of success at Kaybob. Initially, horizontal wells were drilled and completed using a five-stage fracture configuration. With success, the Company began using a seven-stage fracture configuration. Most recently, Celtic has employed eleven to sixteen-stage fractures with positive results. As a result of the Company's recent success with eleven to sixteen-stage fracture completions, Celtic expects to realize significant gains in productivity and higher recovery rates of gas-in-place, with a smaller percentage increase in capital spending. Ultimately, the Company expects these newer horizontal wells to recover more reserves at a lower per unit cost.

To date at Kaybob, the highest average initial raw natural gas production rate for a well completed in the Triassic Montney formation has been 16.6 mmcf per day and for a well completed in the Cretaceous Bluesky formation, the highest initial production rate has been 15.1 mmcf per day.

The economics of developing these natural gas reservoirs at Kaybob are further enhanced by associated recoverable liquids. The average liquids content in the Montney at Kaybob is approximately 26 bbls (40% NGLs and 60% condensate) per mmcf of raw gas and in the Bluesky, it is approximately 40 bbls (85% NGLs and 15% condensate) per mmcf of raw gas.

In addition to the Triassic and Cretaceous formations, Celtic has a large undeveloped land position in the Devonian Duvernay shale. This formation has attracted significant interest in recent months as is evidenced by the substantial amounts of capital that were incurred by other companies at recent Alberta crown land sales accumulating Duvernay rights in close proximity to Kaybob. Celtic expects to drill an exploration well targeting the Duvernay shale in 2010.

Celtic also has the following unit interests in the Greater Kaybob area: Kaybob South Unit # 1 - 9.3% unit interest in 40 sections of unitized rights in the Beaverhill Lake; Kaybob South Unit # 2 - 61.4% unit interest in 26 sections of unitized rights in the Beaverhill Lake; and Kaybob South Unit # 3 - 10.2% unit interest in 50.25 sections of unitized rights in the Beaverhill Lake.

In the greater Kaybob area where the Company has been actively pursuing Montney, Bluesky and Notikewin prospects, Celtic also has opportunities in other formations including the Jurassic Nordegg and Devonian Beaverhill Lake and intends to commence a program in the Devonian Duvernay.

In the Company's December 31, 2009 reserve evaluation, Sproule Associates Limited ("Sproule") has assigned reserves to 33.6 net un-drilled wells in the Montney formation, 3.7 net un-drilled wells in the Bluesky formation, 1.6 net un-drilled wells in the Notikewin formation, 2.0 net un-drilled wells in the Nordegg formation and 4.1 net un-drilled wells in the Beaverhill Lake formation. Reserves were not assigned to future potential drilling in the Duvernay formation.

The following table outlines the reserves included in the December 31, 2009 reserve evaluation in the Greater Kaybob area:

KAYBOB RESERVES

	Montney	Bluesky Horizontal	Notikewin Horizontal	Other	Total Kaybob
Proved Reserves					
Natural gas *(mmcf)*	99,862	13,729	1,583	26,855	142,029
NGLs *(mBOE)*	2,985	489	57	2,135	5,666
Combined *(mBOE)*	19,629	2,777	321	6,611	29,338
Net present value 10% BT *($000's)*	312,534	56,900	5,323	99,691	474,448
Number of net wells - producing	69.8	6.6	1.8	25.9	104.1
Number of net wells - un-drilled locations	20.7	2.4	0.8	3.1	27.0
Proved plus Probable Reserves					
Natural gas *(mmcf)*	170,407	23,923	5,706	43,597	243,633
NGLs *(mBOE)*	5,041	854	206	3,482	9,583
Combined *(mBOE)*	33,442	4,841	1,157	10,748	50,188
Net present value 10% BT *($000's)*	500,500	92,517	19,605	152,944	765,566
Number of net wells - producing	69.8	6.6	1.8	25.9	104.1
Number of net wells - un-drilled locations	33.6	3.7	1.6	6.1	45.0

Looking ahead to 2010, Celtic will use its knowledge and experience with horizontal multi-stage fracture drilling and completion technology in other areas in west central Alberta with the objective of developing new resource plays similar to the Company's Kaybob resource plays. At present, the Company has amassed 46,400 acres of undeveloped lands on several exploration plays targeting natural gas reservoirs in the Triassic Montney and Cretaceous Bluesky, Notikewin and Cardium formations, outside of Celtic's existing Kaybob operating area. The Company expects to have tested each one of these exploration plays by mid-year 2010.

In February 2010, Celtic announced that it had entered into an agreement to divest its interest in assets located at Swan Hills, Alberta. This transaction is effective February 1, 2010 and is expected to close on or about March 31, 2010. The Company expects to receive proceeds of $53.2 million, before closing adjustments. At December 31, 2009, proved reserves assigned to these assets were 1.1 million BOE and proved plus probable reserves were 2.0 million BOE. Production from these assets at the time of announcement was approximately 500 BOE per day. As a result, the Company is selling proved reserves for $49.40 per BOE and proved plus probable reserves for $26.61 per BOE. Proceeds for production equates to $106,500 per daily flowing BOE. These calculations are before deducting land values and before future capital required to develop reserves.

The Company expects to re-deploy a portion of the proceeds from this disposition towards Celtic's 2010 drilling and land acquisition program. The balance will initially be used to pay down bank debt, leaving the Company with higher unused credit lines that can be accessed as opportunities arise.

As we leave 2009, after experiencing a difficult economic environment, Celtic was able to thrive as a result of prudent financial management and successful operating performance, and continues to be well positioned to take advantage of further growth opportunities. We look forward to continued growth in production and cash flow in 2010 and thereafter.

We would like to thank our shareholders for their support, our Board of Directors for their guidance and our employees for their continued effort and loyalty.

David J. Wilson President and Chief Executive Officer
March 3, 2010

KAYBOB UNDEVELOPED LAND
AS AT DECEMBER 31, 2009

GROSS ACRES

MONTNEY RIGHTS
102,720

BLUESKY RIGHTS
37,280

NOTIKEWIN RIGHTS
34,240

NORDEGG RIGHTS
102,080

DUVERNAY RIGHTS
93,920

NET ACRES

MONTNEY RIGHTS
89,874

BLUESKY RIGHTS
22,995

NOTIKEWIN RIGHTS
22,011

NORDEGG RIGHTS
88,226

DUVERNAY RIGHTS
87,476

AVERAGE WORKING INTEREST

MONTNEY RIGHTS
87%

BLUESKY RIGHTS
62%

NOTIKEWIN RIGHTS
64%

NORDEGG RIGHTS
86%

DUVERNAY RIGHTS
93%

MANAGEMENT'S DISCUSSION AND ANALYSIS

CELTIC EXPLORATION LTD.

INTRODUCTION

Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated on April 16, 2002. Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the symbol "CLT".

The following management's discussion and analysis ("MD&A") should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2009. This MD&A is effective March 3, 2010. The accompanying financial statements of Celtic have been prepared by management and approved by the Company's Audit Committee and Board of Directors. These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Additional information relating to Celtic can be found on the SEDAR website at www.sedar.com.

Non–GAAP Financial Measurements

This document contains the terms "funds from operations", "operating netback", "production per share" and "net asset value" which do not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Funds from operations and operating netbacks are used by Celtic as key measures of performance. Funds from operations and operating netbacks are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Operating netbacks are determined by deducting royalties, production expenses and transportation expenses from oil and gas revenue. Funds from operations are determined by adding back settlement of asset retirement obligations and change in non-cash operating working capital to cash provided by operating activities. The Company calculates funds from operations per share using the same method and shares outstanding which are used in the determination of earnings per share.

Other Measurements

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to oil in this discussion include crude oil and natural gas liquids ("NGLs"). NGLs include condensate, propane, butane and ethane. References to gas in this discussion include natural gas and sulphur. Sulphur volumes have been converted to natural gas equivalence at one long tonne per 10 thousand cubic feet.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company.

Capitalized costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved reserves.

The carrying value of property, plant and equipment is reviewed annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, future oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Liability recognition for asset retirement obligations associated with oil and gas well sites and facilities are determined using estimated costs discounted based on the estimated life of the asset. Capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. Over time, the liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation.

In order to recognize stock based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on Celtic's financial statements.

Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated on April 16, 2002. Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the symbol "CLT".

Changes in Accounting Policies and Practices

The following new or revised Canadian Institute of Chartered Accountants ("CICA") Handbook sections became effective January 1, 2009:

Section 3064, *Goodwill and Intangible Assets*; and
Section 3862, *Financial Instruments – Disclosures*.

Section 3064 clarifies the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Adoption of this standard has been applied retroactively and has had no impact on the Company's financial statements.

Section 3862 was revised to include a hierarchy concept in measuring financial instruments, a requirement to provide disclosure concerning the fair value measurements of assets and liabilities for each hierarchy level and amendments to the liquidity disclosure requirements. The impact to the Company's financial statements as a result of adopting this amended standard is reflected in Note 10 of these financial statements.

The following new or revised Canadian Institute of Chartered Accountants ("CICA") Handbook sections became effective July 1, 2009:

Section 1601, *Consolidated Financial Statements*; and
Section 1582, *Business Combinations*.

Section 1601 establishes standards for the preparation of consolidated financial statements. These recommendations are effective January 1, 2011 with early adoption permitted. There is no impact on the Company's financial statements at this time.

Section 1582 establishes principles for the measurement of assets, liabilities and contingencies acquired at fair value, as well as recognizing acquisition-related and reorganization costs separately from the business combination within the statement of operations. These recommendations are effective for business combinations occurring after January 1, 2011, although early adoption is permitted. There is no impact on the Company's financial statements at this time.

Future Changes in Accounting Practices

In February 2007, the CICA's Accounting Standards Board ("AcSB") confirmed that publicly accountable profit-oriented enterprises will be required to use International Financial Reporting Standards ("IFRS") in interim and annual financial statements for fiscal years beginning on or after January 1, 2011. Comparatives must be prepared on the same basis. IFRS will replace Canada's current GAAP for these enterprises. The Company retained the services of an external advisor to provide a diagnostic review and advisory services to support the Company's IFRS conversion plan. Celtic is currently reviewing the diagnostic document that has been prepared and expects to adopt the new IFRS standards by the applicable dates. At the present time, the impact of the adoption of IFRS on the Company's financial statements is not determinable.

Disclosure Controls and Procedures

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The CEO and CFO have evaluated the effectiveness of Celtic's disclosure controls and procedures as at December 31, 2009 and have concluded that such disclosure controls and procedures are effective.

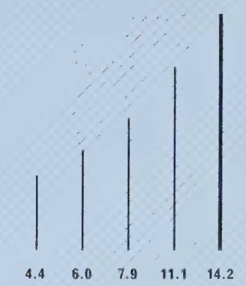
Internal Controls over Financial Reporting

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred during the period from October 1, 2009 to December 31, 2009 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes were identified during this period.

The CEO and CFO have evaluated the effectiveness of Celtic's internal controls over financial reporting as at December 31, 2009 and have concluded that such internal controls over financial reporting are effective.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.



PRODUCTION
(MBOE) 2005 – 2009

GROWTH STRATEGY

Celtic's growth strategy is dual-pronged. The Company seeks to acquire assets with exploitation potential and, at the same time, implements its full cycle exploration and development program. This strategy has proved successful to date as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002. To complement this strategy, the Company has assembled a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities. Celtic believes that its growth strategy will continue to increase production per share.

RESULTS OF OPERATIONS

2009 Highlights

The year ended December 31, 2009 was another successful year in the execution of the Company's growth strategy. Highlights for 2009 are as follows:

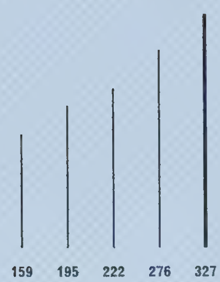
- Drilled 55 (43.0 net working interest) wells during 2009 resulting in 50 (38.9 net) gas wells and 1 (0.3 net) oil well, for an overall success rate, based on net wells, of 91%;
- Increased average daily production by 28% to 14,192 BOE per day, up from 11,071 BOE per day in 2008 and achieved daily average production per million shares of 327 BOE per day, up 18% in 2009 compared to 276 BOE per day in the previous year;
- Increased proved plus probable reserves by 13% to 60.4 million BOE, up from 53.6 million BOE at December 31, 2008 and replaced 2009 production by a factor of 2.3 times;
- Reported finding, development and acquisition cost (including future development capital) of $9.84 per BOE resulting in a recycle ratio of 2.5 times based on proved plus probable reserves;
- Reported net asset value at year-end of $19.76 per share, based on net present value of reserves discounted at 10%, before tax and using forecasted 2010 average commodity prices of US$79.17 per barrel for WTI oil and $5.08 per GJ for AECO gas;
- Accumulated additional undeveloped land in new resource play prospects targeting the Triassic Montney, Cretaceous Bluesky, Cretaceous Notikewin and Devonian Duvernay formations in west central Alberta;
- Generated gross proceeds of $36.4 million by completing an equity financing that resulted in the issuance of 2.8 million common shares at a price of $13.25 per share; and
- Reported funds from operations per share, diluted, of $2.70, a decrease of 17% from $3.27 per share in the previous year.

Production

Oil and gas production in 2009 increased 28% to average 14,192 BOE per day compared to 11,071 BOE per day in 2008. Average production in the fourth quarter of 2009 was 17,274 BOE per day, up 43% from 12,059 BOE per day in the fourth quarter of 2008. Production per million shares outstanding in 2009 averaged 327 BOE per day, up 18% from 276 BOE per day in 2008.

The following table provides a summary of daily average production for 2009 and 2008:

PRODUCTION SUMMARY	Year ended December 31, 2009	Year ended December 31, 2008	Percent Change
Oil *(bbls/d)*	3,687	3,404	8%
Gas *(mcf/d)*	63,028	46,000	37%
Combined *(BOE/d)*	**14,192**	**11,071**	**28%**
Production per million shares *(BOE/d)*	**327**	**276**	**18%**



PRODUCTION PER MILLION SHARES
(BOE/D) 2005 – 2009

Celtic's production is entirely based in Alberta and is divided into four core areas. In Southern Alberta, the Company's primary natural gas producing properties are located at Drumheller, Michichi and Richdale and its primary oil producing properties are located at Princess and Bantry. In East Central Alberta, the principal producing asset is a shallow natural gas property at Ashmont and Figure Lake. In Northern Alberta, the Company produces mainly light oil from Ogston, Otter and Utikuma Lake. In West Central Alberta, Celtic has both natural gas and light oil production at Kaybob and Swan Hills. West Central Alberta was the Company's most active drilling area in 2009 and approximately 89% of Celtic's production in 2009 came from this area.

The following table provides a summary of comparative daily average production in each core area:

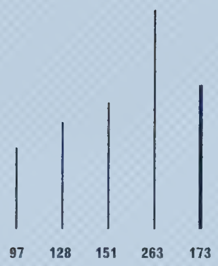
PRINCIPAL PRODUCING AREAS *(BOE/d)*	Year ended December 31, 2009	Year ended December 31, 2008	Percent Change
West Central Alberta	12,655	9,083	39%
Southern Alberta	1,042	1,330	-22%
East Central Alberta	288	350	-18%
Northern Alberta	207	308	-33%
Total	**14,192**	**11,071**	**28%**

Revenue

Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the year ended December 31, 2009 was $172.6 million, a decrease of 34% compared to $263.3 million in the previous year. For the three months ended December 31, 2009, revenue was $60.1 million, up 16% from $51.8 million in the fourth quarter of 2008.

The breakdown of revenue for 2009 and 2008 is summarized in the following table:

REVENUE	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change	
	$ 000's	$/BOE	$ 000's	$/BOE	$ 000's	$/BOE
Oil revenue	75,971	56.45	112,735	90.48	-33%	-38%
Gas revenue	96,642	25.21	150,602	53.67	-36%	-53%
Royalties	(22,968)	(4.43)	(58,449)	(14.42)	-61%	-69%
Realized gain (loss) on financial instruments	34,294	7.10	(19,766)	(4.88)	-	-
Unrealized gain (loss) on financial instruments	(33,523)	(6.47)	32,304	7.97	-	-
Revenue	**150,416**	**29.53**	**217,426**	**53.67**	**-31%**	**-45%**



REVENUE BEFORE ROYALTIES AND FINANCIAL INSTRUMENTS
($ Millions) 2005 – 2009

Lower revenue in 2009 was primarily a result of lower commodity prices which more than offset increased production levels. The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the year ended December 31, 2009 was $40.43 per BOE ($33.33 per BOE before financial instruments), a decrease of 33% (a decrease of 49% before financial instruments) compared to the previous year. For the three months ended December 31, 2009, the average adjusted product price received was $42.17 per BOE ($37.85 per BOE before financial instruments), down 18% (down 19% before financial instruments) from the average price received in the fourth quarter of 2008.

Oil Operations

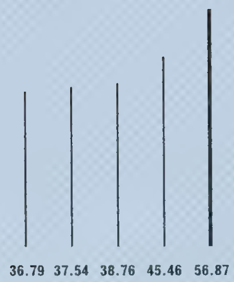
Oil production for the year ended December 31, 2009 averaged 3,687 bbls per day, an increase of 8% compared to the previous year. For the three months ended December 31, 2009, average oil production was 4,384 bbls per day, up 23% from the fourth quarter of 2008. Increased oil production in 2009 reflects the addition of NGLs from the increased liquids-rich natural gas production at Kaybob, Alberta.

The average price received for oil sales, after realized financial instruments, for the year ended December 31, 2009 was $81.00 ($56.45 before financial instruments) per barrel, down 2% (down 38% before financial instruments) from the average price of $82.45 ($90.48 before financial instruments) per barrel received in 2008. The Company recorded a realized gain of $33.0 million on financial instruments relating to oil price transactions in 2009 compared to a realized loss of $10.0 million in the previous year. The average price received for oil sales, after realized financial instruments, for the fourth quarter ended December 31, 2009 was $80.22 ($64.46 before financial instruments) per barrel, up 17% (up 22% before financial instruments) from the average price of $68.63 ($52.81 before financial instruments) per barrel received in the fourth quarter of 2008.

For the twelve months ended December 31, 2009, average oil royalties were 13.3% of revenue, after financial instruments (19.0% of revenue, before financial instruments). In the previous year, average oil royalties were 27.5% of revenue, after financial instruments (25.1% of revenue, before financial instruments). Lower royalty rates, before financial instruments, in 2009 were primarily a result of lower oil prices received, compared to the previous year. For the quarter ended December 31, 2009, average oil royalties were 11.1% of revenue, after financial instruments (13.9% of revenue, before financial instruments). In the fourth quarter of the previous year, average oil royalties were 18.5% of revenue, after financial instruments (24.0% of revenue, before financial instruments).

Transportation expenses for oil production in 2009 averaged $0.27 per barrel compared to $0.53 per barrel in 2008. Lower per unit transportation expenses in 2009 reflect the larger portion of newer NGL production which is mostly pipeline connected and therefore less expensive to transport compared to trucking crude oil. Transportation expenses for oil production in the fourth quarter of 2009 averaged $0.25 per barrel compared to $0.41 per barrel in the fourth quarter of 2008.

For the year ended December 31, 2009, production expenses were $13.11 per barrel, an improvement from the previous year's $13.76 per barrel. During the fourth quarter of 2009, production expenses averaged $12.37 per barrel compared to $12.95 per barrel in the fourth quarter of 2008. Lower per barrel production expenses in 2009 compared to the previous year are primarily a result of the larger component of NGLs included in oil production which are less costly to produce than Celtic's crude oil production.



OIL NETBACK
($/BBL) 2005 - 2009

The breakdown of oil netbacks for 2009 and 2008 are summarized in the following table:

OIL NETBACK	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change
	bbls/d	$/bbl	bbls/d	$/bbl	
Daily average production	**3,687**		**3,404**		8%
Sales price		56.45		90.48	-38%
Gain (loss) on financial instruments		24.55		(8.03)	-
Royalties		(10.75)		(22.70)	-53%
Production expense		(13.11)		(13.76)	-5%
Transportation expense		(0.27)		(0.53)	-49%
Oil netback		**56.87**		**45.46**	**25%**

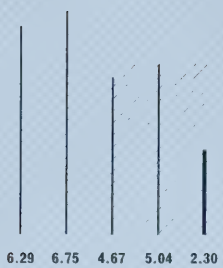
Gas Operations

Gas production for the year ended December 31, 2009 averaged 63,028 mcf per day, an increase of 37% compared to 46,000 mcf per day in the previous year. Increases in gas production in 2009 were primarily a result of Celtic's successful drilling results in its resource development prospect located at Kaybob, Alberta. Gas production for the fourth quarter ended December 31, 2009 averaged 77,339 mcf per day, an increase of 52% compared to the corresponding period of the previous year.

The average price received for gas sales, after realized financial instruments, for the year ended December 31, 2009 was $4.36 ($4.20 before financial instruments) per mcf, down 48% (down 53% before financial instruments) from the average price of $8.37 ($8.94 before financial instruments) per mcf received in 2008. The Company recorded a realized gain of $3.7 million on financial instruments relating to gas price transactions in 2009 compared to a realized loss of $9.6 million in the previous year. The average price received for gas sales, after realized financial instruments, for the fourth quarter ended December 31, 2009 was $4.86 ($4.79 before financial instruments) per mcf, down 34% (down 35% before financial instruments) from the average price of $7.36 ($7.36 before financial instruments) per mcf received in the fourth quarter of 2008.

For the year ended December 31, 2009, average gas royalties were 8.5% of revenue, after financial instruments (8.8% of sales, before financial instruments). In the previous year, average natural gas royalties were 21.4% of revenue, after financial instruments (20.0% of sales, before financial instruments). Actual Crown natural gas royalties payable are determined based on an Alberta reference price and not on actual corporate realized prices. For the quarter ended December 31, 2009, average natural gas royalties were 4.3% of revenue, after financial instruments (4.4% of sales, before financial instruments). In the fourth quarter of the previous year, average natural gas royalties were 19.2% of revenue, after financial instruments (19.2% of sales, before financial instruments).

The New Well Royalty Reduction ("NWRR") drilling incentive program was introduced by the Alberta government in early 2009 and provides for a flat 5% royalty on new wells brought on production after March 31, 2009. This program applies to all new wells brought on production prior to April 1, 2011. The 5% royalty remains in effect for twelve producing months or for the first 500,000 MCF equivalent of gas (or 50,000 barrels of oil equivalent) produced, whichever comes first. Celtic's horizontal wells at Kaybob benefit significantly from this program since the flat 5% royalty will replace first year royalty rates which are normally high during the first year as a result of high flush production rates. Celtic's lower gas royalty rates in 2009, before financial instruments, are a result of lower natural gas selling prices, longer depth horizontal wells which receive favourable treatment under the Alberta royalty framework and new production qualifying for reduced royalty rates under the NWRR program. In addition, royalties are reduced further as the Company continues to receive gas cost allowance ("GCA") credits which do not fluctuate with gas prices.



GAS NETBACK
($/MCF) 2005 – 2009

Transportation expenses for the year ended December 31, 2009 were $0.15 per mcf, an increase of 50% compared to $0.10 per mcf for the previous year. Higher transportation expenses in 2009 reflect the increase in gas production that is transported on third party pipeline infrastructure. Transportation expenses for the fourth quarter ended December 31, 2009 were $0.16 per mcf, an increase of 45% compared to $0.11 per mcf for the same period in the previous year.

For the twelve months ended December 31, 2009, production expenses of $1.54 per mcf were 7% higher than $1.44 per mcf in the previous year. Higher production expenses in 2009 reflect the additional expenses incurred at Kaybob where a significant amount of the Company's production is processed through the KA Gas Plant. This plant was down for approximately five weeks in the second quarter of 2009 for turnaround operations that occur every four years. For the fourth quarter ended December 31, 2009, production expenses were $1.48 per mcf compared to $1.45 per mcf in the fourth quarter of 2008.

The breakdown of natural gas netbacks are summarized in the following table:

GAS NETBACK	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change
	mcf/d	$/mcf	mcf/d	$/mcf	
Daily average production	**63,028**		**46,000**		37%
Sales price		4.20		8.94	-53%
Gain (loss) on financial instruments		0.16		(0.57)	-
Royalties		(0.37)		(1.79)	-79%
Production expense		(1.54)		(1.44)	7%
Transportation expense		(0.15)		(0.10)	50%
Gas netback		**2.30**		**5.04**	**-54%**

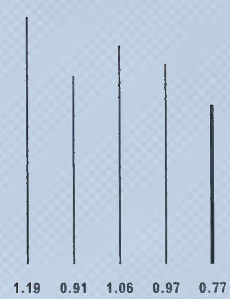
Interest Expense

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada and including HSBC Bank Canada, Canadian Western Bank, Royal Bank of Canada and Fortis Capital (Canada) Ltd. The authorized borrowing amount under this facility is $215.0 million. The facilities are available for a period of 364 days, maturing on June 29, 2010. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Covenants include a current ratio test, reporting requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 1.5% to bank prime plus 3.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 2.5% to 4.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times.

The Company has entered into interest rate swap transactions whereby borrowings through bankers' acceptances in the amount of $100.0 million maturing on April 22, 2011 has been fixed at an annual interest rate of 3.2% up to April 22, 2010 and 2.1% from April 22, 2010 to April 21, 2011, before bank stamping fees.

Interest expense for the year, before financial instruments, was $5.0 million at an average rate of 3.3% compared to $6.1 million at an average rate of 4.8% in 2008.



G&A EXPENSES
($/BOE) 2005 – 2009

INTEREST EXPENSE	Year ended December 31, 2009	Year ended December 31, 2008	Percent Change
	$ 000's	$ 000's	
Interest expense	5,025	6,122	-18%
Average bank debt outstanding	151,410	126,929	19%
Average interest rate *(%)*	**3.3%**	**4.8%**	**-31%**

The Company recorded a realized loss of $2.4 million on financial instruments relating to interest rate swap transactions in 2009 compared to a realized loss of $0.2 million in the previous year.

General and Administrative Expenses

General and administrative ("G&A") expenses for the year ended December 31, 2009 were $3.9 million or $0.77 per BOE compared to $4.0 million or $0.97 per BOE in 2008. G&A expenses are reduced by overhead recovered on Company operated properties. In addition, salaries relating to geological and geophysical personnel are capitalized.

The following table provides a breakdown of G&A expenses:

GENERAL AND ADMINISTRATIVE EXPENSES	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change	
	$ 000's	$/BOE	$ 000's	$/BOE	$ 000's	$/BOE
Gross G&A expenses	8,012	1.55	7,708	1.90	4%	-18%
Overhead recoveries	(3,639)	(0.70)	(3,324)	(0.82)	9%	-15%
Capitalized overhead	(426)	(0.08)	(434)	(0.11)	-2%	-27%
G&A expenses	**3,947**	**0.77**	**3,950**	**0.97**	**0%**	**-21%**

EMPLOYEES	At December 31, 2009	At December 31, 2008	Percent Change
Head office	39	35	11%
Field operations	13	12	8%
Total employees	**52**	**47**	**11%**

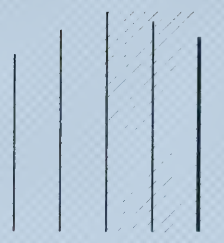
Celtic continues to operate with low G&A expense per BOE compared to many of its peers and is able to do so primarily due to the fact that the Company's operations are geographically focused and concentrated with the majority of its production coming from the greater Kaybob area of Alberta. With 39 head office employees, G&A expense per employee in 2009 averaged $101,203 per employee. This is a 10% reduction from $112,845 per employee in 2008.

Stock Based Compensation Expense

Stock based compensation expense is a non-cash charge which reflects the value of stock options awarded to directors, employees and certain consultants. The value is recognized as an expense over the period from the grant date to the date of vesting of the award.

For the year ended December 31, 2009, stock based compensation expense was $2.4 million, compared to $1.9 million in 2008.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions shown in the following table:



DD&A EXPENSE
($/BOE) 2005 – 2009

STOCK BASED COMPENSATION EXPENSE	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change	
	$ 000's	$/BOE	$ 000's	$/BOE	$ 000's	$/BOE
Stock based compensation expense	**2,362**	**0.46**	**1,858**	**0.46**	**27%**	**0%**
Weighted average assumptions for stock options granted:						
Risk-free interest rate	0.50%		3.07%		-84%	
Expected life in years	3.0		3.0		0%	
Expected volatility	30%		22%		36%	
Expected dividend yield	-		-		-	

On a barrel of oil equivalent basis, stock based compensation expense was $0.46 per BOE in 2009, unchanged from 2008.

Provision for Non–recoverable Accounts Receivable

Celtic has expensed $31.2 million ($13.2 million in 2009 and $18.0 million in 2008) as a provision for non-recoverable accounts receivable relating to a total financial exposure of approximately $32.5 million. The exposure was created with the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the *Companies' Creditors Arrangement Act Canada ("CCAA")* in the Court of Queen's Bench of Alberta Judicial District of Calgary. The total amount of the financial exposure primarily relates to the Company's natural gas and associated by-product sales to SemCAMS during the period from June 1, 2008 to July 21, 2008.

Depletion, Depreciation and Accretion

The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of oil and gas reserves are capitalized. These capitalized costs along with estimated future development capital expenditures to be incurred in order to develop proved reserves, are depleted on a unit of production basis using estimated proved oil and gas reserves. Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25%. Estimated future costs relating to asset retirement obligations are provided for on a unit of production basis, and the provision is included in depletion, depreciation and accretion ("DD&A").

DD&A expense for the period ended December 31, 2009 was $101.8 million or $19.65 per BOE, compared to the previous year's amount of $85.6 million or $21.13 per BOE.

The following table provides a summary of the amounts included in DD&A:

DEPLETION, DEPRECIATION AND ACCRETION	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change	
	$ 000's	$/BOE	$ 000's	$/BOE	$ 000's	$/BOE
Depletion - intangible oil and gas assets	76,873	14.84	63,738	15.74	21%	-6%
Depreciation - tangible oil and gas assets	23,586	4.55	20,580	5.08	15%	-10%
Depreciation - furniture and office equipment	213	0.04	196	0.05	9%	-20%
Amortization - asset retirement costs	616	0.12	614	0.15	0%	-20%
Accretion of asset retirement obligation	520	0.10	458	0.11	14%	-9%
Depletion, depreciation and accretion	**101,808**	**19.65**	**85,586**	**21.13**	**19%**	**-7%**

INCOME TAX DEDUCTIONS
($ Millions) 2005 - 2009

Ceiling Test

The Company performed a ceiling test calculation at December 31, 2009 in accordance with the CICA full cost accounting guidelines. As a result of the calculation, Celtic was not required to record an impairment loss. In addition, based on the calculation in the previous year conducted at December 31, 2008, there was no impairment loss required.

The forecasted future oil and gas prices for the next five years used in the ceiling test evaluation of the Company's proved reserves as at December 31, 2009 were as follows:

FORECAST PRICES	2010	2011	2012	2013	2014
Oil *($/bbl)*	$ 78.34	$ 83.91	$ 85.37	$ 88.16	$ 89.36
NGLs *($/bbl)*	66.24	71.50	73.95	77.21	79.05
Natural gas *($/mcf)*	5.56	6.48	6.72	7.58	8.39

Prices escalate at varying percentages in a range between 1.7% and 2.4% thereafter.

Taxes

In 2009, Celtic provided for a recovery of future income taxes in the amount of $9.6 million and in 2008, Celtic recorded a provision for future income taxes in the amount of $14.0 million. These amounts differ from the expected provision for (recovery of) income taxes based on the statutory combined income tax rate of 29.0% in 2009 and 29.5% in 2008 due to the differences between non-deductible stock based compensation expense and the recognition of a benefit primarily relating to substantively enacted changes to future federal and provincial income tax rates. An analysis of the income tax provision is included in the notes to the financial statements.

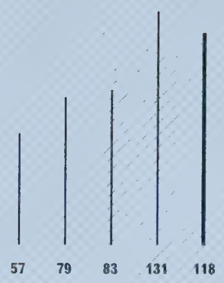
At December 31, 2009, Celtic had estimated unused income tax deductions available of approximately $412.2 million. A summary of these deductions with corresponding rates of deductibility is shown in the table below:

INCOME TAX DEDUCTIONS	As at December 31, 2009		As at December 31, 2008		Percent Change
	$ 000's	Deduction rate	$ 000's	Deduction rate	
Canadian oil and gas property expense (COGPE)	98,500	10%	98,952	10%	0%
Canadian development expense (CDE)	157,800	30%	125,352	30%	26%
Canadian exploration expense (CEE)	43,600	100%	31,234	100%	40%
Undepreciated capital cost (UCC)	107,800	4% to 30%	104,874	4% to 30%	3%
Share issue costs	4,500	5 years	4,960	5 years	-9%
Income tax deductions	**412,200**		**365,372**		**13%**

Funds from Operations and Cash Provided by Operating Activities

Funds from operations is a non-GAAP measure defined as cash provided by operating activities before changes in non-cash operating working capital and settlement of asset retirement obligations. Despite being a non-GAAP measure, funds from operations is commonly used in the oil and gas industry and by Celtic to assist in measuring the Company's ability to finance capital programs and meet financial obligations.

Funds from operations for the year ended December 31, 2009 was $118.0 million ($2.72 per share, basic and $2.70 per share, diluted). In 2008, funds from operations were $131.4 million ($3.28 per share, basic and $3.27 per share, diluted). Funds from operations for the three months ended December 31, 2009 was $42.0 million ($0.94 per share, basic and $0.93 per share, diluted). In the fourth quarter of 2008, funds from operations were $32.0 million ($0.78 per share, basic and $0.78 per share, diluted).



FUNDS FROM OPERATIONS
($ Millions) 2005 – 2009

On a barrel of oil equivalent basis, funds from operations in 2009 were $22.78 per BOE, down 30% from $32.44 per BOE in 2008. The primary reason for the decrease in 2009 was a result of lower oil and gas prices realized during the year, which more than offset the lower aggregate expenses in 2009 compared to the previous year. On a barrel of oil equivalent basis, funds from operations in the fourth quarter of 2009 were $26.44 per BOE, down 8% from $28.89 per BOE in the fourth quarter of 2008.

The following table provides a reconciliation of funds from operations for the past two years:

FUNDS FROM OPERATIONS *($ 000's)*	Year ended December 31, 2009	Year ended December 31, 2008	Percent Change
Cash provided by operating activities	103,721	89,254	16%
Settlement of asset retirement obligations	1,043	806	29%
Change in non-cash operating working capital	13,261	41,300	-68%
Funds from operations	**118,025**	**131,360**	**-10%**

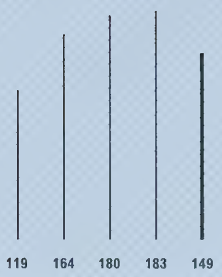
Cash provided by operating activities for the year ended December 31, 2009 was $103.7 million, up 16% from $89.3 million in 2008. Cash provided by operating activities for the three months ended December 31, 2009 was $33.9 million, up 47% from $23.0 million in the fourth quarter of 2008.

Net Earnings

Net loss for the year ended December 31, 2009 was $23.3 million ($0.54 per share, basic and diluted). Net earnings for the year ended December 31, 2008 was $44.2 million ($1.10 per share, basic and diluted). Net earnings for the three months ended December 31, 2009 was $0.9 million ($0.02 per share, basic and diluted). Net earnings for the fourth quarter of 2008 were $29.6 million ($0.72 per share, basic and diluted).

The following table provides detailed unit statistics on a barrel of oil equivalent basis:

UNIT STATISTICS	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change
	BOE/d	$/BOE	BOE/d	$/BOE	
Daily average production	**14,192**		**11,071**		**28%**
Sales price		**33.33**		**65.00**	**-49%**
Gain (loss) on financial instruments		7.10		(4.88)	-
Royalties		(4.43)		(14.42)	-69%
Production expense		(10.26)		(10.21)	0%
Transportation expense		(0.74)		(0.57)	30%
Operating netback		**25.00**		**34.92**	**-28%**
General and administrative expense		(0.76)		(0.97)	-22%
Interest expense, including financial instruments		(1.46)		(1.51)	-3%
Funds from operations		**22.78**		**32.44**	**-30%**
Unrealized gain (loss) on financial instruments		(6.47)		7.97	-
Stock based compensation expense		(0.46)		(0.46)	0%
Depletion, depreciation and accretion		(19.65)		(21.13)	-7%
Provision for non-recoverable accounts receivable		(2.55)		(4.44)	-43%
Future income tax		1.86		(3.45)	-
Net earnings (loss)		**(4.49)**		**10.93**	**-**



CAPITAL EXPENDITURES
($ Millions) 2005 – 2009

INVESTMENT AND INVESTMENT EFFICIENCIES

Capital Expenditures

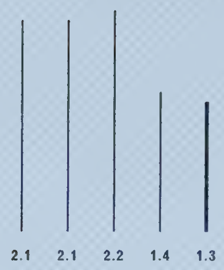
Celtic is committed to future growth through its strategy to augment strategic oil and gas acquisitions with exploitation upside, and at the same time, implement a full cycle exploration and development program. Since the Company began active oil and gas operations in September 2002, Celtic has completed several acquisitions in order to establish a cash flow platform and an inventory of exploration and development prospects from which the Company can grow through the drill bit. Examples of where Celtic has successfully employed its strategy to acquire an initial position in an area and subsequently expand the area making it core to the Company include Princess/Bantry, Ashmont and Fox Creek. Examples of where Celtic has successfully employed its strategy to acquire assets in existing operating areas in order to expand its inventory of developments prospects include Kaybob South, Lower Kaybob South and KayFox.

During the year ended December 31, 2009, Celtic incurred $147.0 million on exploration and development activity, $2.2 million on property acquisitions and recorded net proceeds of $0.4 million from property dispositions. Drilling and completion operations accounted for $125.3 million and the Company earned $20.6 million in drilling royalty credits that are eligible to be claimed against corporate crown royalties payable. Equipment and facility expenditures were $32.1 million. The balance of $10.2 million was spent on land and seismic, building the Company's inventory of prospects for future drilling opportunities. Approximately 96% of net wells drilled were categorized as development and 4% were exploratory.

During the year ended December 31, 2008, Celtic incurred $138.4 million on exploration and development activity, $49.4 million on property acquisitions and recorded net proceeds of $4.3 million from property dispositions. Drilling and completion operations accounted for $102.8 million and equipment and facility expenditures were $30.3 million. The balance of $5.3 million was spent on land and seismic, building the Company's inventory of prospects for future drilling. Approximately 79% of net wells drilled were development and 21% were exploratory.

The Company's capital expenditures, including acquisitions and dispositions, for 2009 and 2008 are summarized in the following table:

CAPITAL EXPENDITURES	Year ended December 31, 2009		Year ended December 31, 2008		Percent Change
	$ 000's	% of total	$ 000's	% of total	
Property, plant and equipment expenditures					
Lease acquisitions and retention	9,464	6%	4,521	2%	109%
Geological and geophysical activity	714	0%	724	0%	-1%
Drilling and completion of wells	125,257	86%	102,785	57%	22%
Drilling royalty credits	(20,619)	-14%	–	–	–
Facilities, pipeline and well equipment	31,896	21%	30,040	16%	6%
Office furniture and equipment	252	0%	326	0%	-23%
	146,964	99%	138,396	75%	6%
Property, plant and equipment acquisitions	2,172	1%	49,406	27%	-96%
Property, plant and equipment dispositions	(375)	0%	(4,325)	-2%	-91%
Corporate acquisitions	–	0%	–	0%	–
Capital expenditures	**148,761**	**100%**	**183,477**	**100%**	**-19%**



CAPEX/FUNDS FROM OPERATIONS RATIO
2005 – 2009

Land Holdings

As at December 31, 2009, Celtic owned 412,654 net acres of land, of which 294,700 net acres were undeveloped. In the previous year, as at December 31, 2008, Celtic owned 358,249 net acres of land, of which 246,629 net acres were undeveloped. The Company's net land holdings increased 15% in 2009 and its undeveloped land holdings increased 19% year over year. Approximately 9% of the Company's undeveloped land position is subject to expiry in 2010, if not developed. Celtic holds an average working interest of 73% in its lands, up from an average working interest of 69% in the previous year.

In 2009 the Company took full advantage of low natural gas prices and the overall downturn in economic activity in the oil and gas industry by participating at land sales in an environment of lower costs in order to continue to build its prospect inventory.

In 2009, Celtic incurred $8.3 million at Alberta Crown land sales acquiring 74,170 net acres of petroleum and natural gas rights at an average cost of $112 per acre; compared to an industry average of $163 per acre. These prices were lower than the previous year in which Celtic spent $4.1 million acquiring 24,000 net acres at an average cost of $171 per acre, compared to the 2008 industry average of $186 per acre.

Since Celtic's inception in 2002, 2009 was the Company's most active year for acquiring petroleum and natural gas rights at Alberta Crown land sales. The majority of Celtic's 2009 land expenditures were directed towards expanding the Company's acreage position in formations such as the Triassic Montney, Cretaceous Bluesky and Cretaceous Notikewin with characteristics that the Company believes are similar to its existing development resource plays at Kaybob, Alberta. In addition, the Company has also assembled a significant land position in the Devonian Duvernay formation in the Greater Kaybob area of Alberta.

The Company evaluates the fair market value of its undeveloped land holdings internally. At December 31, 2009, the fair market value of Celtic's net undeveloped land was $56.6 million or $192 per acre up from $48.3 million or $196 per acre at December 31, 2008.

The following table summarizes Celtic's land holdings as at December 31, 2009 and 2008:

LAND HOLDINGS

	As at December 31, 2009		As at December 31, 2008		Percent Change	
(Acres)	Gross	Net	Gross	Net	Gross	Net
Developed	204,795	117,954	197,021	111,620	4%	6%
Undeveloped	363,473	294,700	318,969	246,629	14%	19%
Total	**568,268**	**412,654**	**515,990**	**358,249**	**10%**	**15%**
Average working interest		**73%**		**69%**		

Looking ahead to 2010, Celtic will continue its internally generated, prospect-driven land acquisition strategy. This strategy will be complemented by third party farm-in arrangements in core exploration and development areas. Celtic's land acquisition strategy remains focused on building a significant base of high working interest operated prospects, ensuring the Company is in a position to control its capital expenditure program.

Drilling

Drilling activity in North America declined significantly in 2009 compared to the previous year as a result of lower oil and gas prices and uncertainty in credit and capital markets. However, Celtic's drilling operations remained active in 2009 as the Company's strong financial position backed by its prudent commodity price risk management strategy and the substantial benefits derived from Alberta's royalty drilling incentive programs, allowed the Company to thrive during difficult economic conditions.

During the year ended December 31, 2009, Celtic drilled 55 (43.0 net) wells, with an overall success rate of 91% on net wells drilled. The Company's average working interest in wells drilled during 2009 was 78%. The split between development drilling and exploratory drilling was 96% and 4%, respectively. In 2009, Celtic's horizontal drilling activity increased resulting in the average measured depth of net wells drilled of 3,289 metres. The Company drilled a total of 141,409 metres during the year.

UNDEVELOPED LAND
(Thousand net acres) 2005 - 2009

In the previous year ended December 31, 2008, Celtic drilled 54 (41.1 net) wells, with an overall success rate of 88% on net wells drilled. The Company's average working interest in wells drilled during 2008 was 76%. The split between development drilling and exploratory drilling was 79% and 21%, respectively. In 2008, the average measured depth of net wells drilled was 2,960 metres.

The following table summarizes Celtic's drilling activity in 2009:

DRILLING ACTIVITY	Development Wells		Exploration Wells		Total Wells	
Year ended December 31, 2009	Gross	Net	Gross	Net	Gross	Net
Natural gas	49	37.9	1	1.0	50	38.9
Coal bed methane	0	0.0	0	0.0	0	0.0
Oil	1	0.3	0	0.0	1	0.3
Dry	3	3.0	1	0.8	4	3.8
Total wells	**53**	**41.2**	**2**	**1.8**	**55**	**43.0**
Success rate, based on net wells		**93%**		**56%**		**91%**

Reserves

Celtic retains Sproule Associates Limited ("Sproule"), an independent qualified reserve evaluator to prepare a report on 100% of its oil and gas reserves. The Company has a Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants.

Reserves as at December 31, 2009 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101"). At December 31, 2009, Celtic's proved plus probable reserves were 60.4 million BOE, up 13% from 53.6 million BOE at the end of 2008.

The following table outlines the change in the Company's reserves year-over-year including discoveries, drilling extensions, improved recoveries, infill drilling, technical revisions, economic factors, dispositions and production:

RESERVES RECONCILIATION	Oil		Gas		Combined	
	Total Proved mbbls	Proved + Probable mbbls	Total Proved mmcf	Proved + Probable mmcf	Total Proved mBOE	Proved + Probable mBOE
Balance, December 31, 2008	**8,321**	**14,372**	**125,330**	**235,353**	**29,209**	**53,598**
Technical revisions	56	(78)	5,628	2,683	994	369
Discoveries	0	0	0	0	0	0
Extensions	853	1,024	29,296	37,726	5,736	7,312
Improved recoveries	0	0	0	0	0	0
Infill drilling	900	972	20,415	16,817	4,303	3,775
Economic factors	39	55	1,032	1,502	211	305
Acquisitions	33	43	896	1,160	182	236
Dispositions	0	0	0	0	0	0
Net additions	1,881	2,016	57,267	59,888	11,426	11,997
Production	(1,346)	(1,346)	(23,005)	(23,005)	(5,180)	(5,180)
Balance, December 31, 2009	**8,856**	**15,042**	**159,592**	**272,236**	**35,455**	**60,415**
Percentage increase in reserves	**6%**	**5%**	**27%**	**16%**	**21%**	**13%**

WELLS DRILLED
(Net) 2005 – 2009

The Company increased the net present value of proved plus probable reserves, discounted at 10% before tax, to $1,011.9 million, up 14% from $891.0 million at December 31, 2008. The reserve life index was 9.6 years compared to 12.1 years at December 31, 2008. At December 31, 2009, the weighting of proved plus probable reserves was 25% oil and 75% gas.

The following table outlines a summary of the Company's reserves at December 31, 2009:

SUMMARY OF RESERVES

As at December 31, 2009	Oil mbbls	Gas mmcf	Combined mBOE	Q4 2009 Production BOE/d	Reserve Life Index Years	NPV 10% BT $M	NPV per BOE $/BOE
Proved developed producing	6,426	101,854	23,402	17,274	3.7	472,544	20.19
Proved developed non-producing	511	8,638	1,951			34,855	17.87
Proved undeveloped	1,919	49,100	10,102			140,790	13.94
Total proved	8,856	159,592	35,455	17,274	5.6	648,189	18.28
Probable additional	6,186	112,644	24,960			363,750	14.57
Total proved plus probable	**15,042**	**272,236**	**60,415**	**17,274**	**9.6**	**1,011,939**	**16.75**

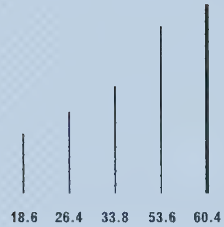
The average price of oil steadily increased in each of the years from 2005 to 2008; however, in 2009 oil prices were considerably lower than the previous year. Average annual natural gas prices at AECO-C from 2005 to 2008 have traded in a narrower range of $6.31 to $8.14 per GJ; however, in 2009, AECO-C averaged a much lower price of $3.97 per GJ.

The following table outlines forecasted future prices that Sproule has used in their evaluation of the Company's reserves at December 31, 2009:

REFERENCE PRICES

			Oil			Natural Gas		
		Currency Exchange Rate US$/CA$	WTI Cushing Oklahoma US$/bbl	Edmonton Light Par CA$/bbl	Forecasted Celtic Oil Price [(1)] CA$/bbl	Henry Hub Louisiana US$/mmbtu	Alberta AECO-C Spot CA$/GJ	Forecasted Celtic Gas Price [(2)] CA$/mcf
Historical:	2005	0.826	56.46	69.29		8.62	8.14	
	2006	0.882	66.09	73.30		7.23	6.79	
	2007	0.935	72.27	77.06		6.86	6.31	
	2008	0.943	99.59	102.85		9.04	7.73	
	2009	0.880	61.63	66.20		4.01	3.97	
Five year historical average		**0.893**	**71.21**	**77.74**		**7.15**	**6.59**	
Future Forecasts:	2010	0.920	79.17	84.25	78.70	5.70	5.08	5.55
	2011	0.920	84.46	89.99	84.58	6.48	5.89	6.47
	2012	0.920	86.89	92.61	85.84	6.70	6.11	6.71
	2013	0.920	90.20	96.19	88.75	7.43	6.86	7.57
	2014	0.920	92.01	98.13	90.01	8.12	7.57	8.39
Five year forecast average		**0.920**	**86.55**	**92.23**	**85.58**	**6.89**	**6.30**	**6.94**
Prior year's five year forecast average		**0.870**	**71.65**	**79.92**	**73.75**	**7.88**	**7.55**	**8.40**
Percentage change in five year forecast		**6%**	**21%**	**15%**	**16%**	**-13%**	**-17%**	**-17%**

(1) Celtic's forecasted average oil price is based on total proved plus probable reserves and does not include NGLs.
(2) Celtic's forecasted average gas price is based on proved plus probable reserves and does not include sulphur.



RESERVES
(MMBOE) 2005 – 2009

Sproule is forecasting WTI oil prices to average US$86.55 per bbl over the next five years, 22% higher than the average price of US$71.21 per bbl over the past five years. For natural gas, AECO-C natural gas prices are forecasted to average $6.30 per GJ over the 2010 to 2014 period, a decrease of 4% from the average price of $6.59 per GJ during the 2005 to 2009 period.

During 2009, the Company's capital expenditures, net of dispositions, resulted in proved plus probable reserve additions of 12.0 million (23.5 million in 2008) BOE, resulting in finding, development and acquisition ("FD&A") costs of $9.84 ($12.24 in 2008) per BOE, including future development capital ("FDC") costs. Proved reserve additions in 2009 were 11.4 million (12.2 million in 2008) BOE, resulting in FD&A costs of $12.89 ($19.43 in 2008) per BOE, including FDC costs.

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per BOE to that years' reserve FD&A cost per BOE. Since incorporation, Celtic has successfully achieved a recycle ratio of 2.3 times on a proved plus probable basis. In 2009, the recycle ratio was 2.5 times.

The following table provides detailed calculations relating to FD&A costs and recycle ratios for 2009 and 2008:

FINDING, DEVELOPMENT & ACQUISITION COSTS	Year ended December 31, 2009	Year ended December 31, 2008	Percent Change	Cumulative Since Incorporation
Proved Reserves				
Capital expenditures *($ 000's)*	148,761	183,477	-19%	936,635
Change in FDC costs required to develop reserves *($ 000's)*	(1,483)	54,106	–	90,473
Total capital costs *($ 000's)*	147,278	237,583	-38%	1,027,108
Reserve additions, net *(mBOE)*	11,426	12,227	-7%	53,153
FD&A cost, before FDC *($/BOE)*	13.02	15.01	-13%	17.62
FD&A cost, including FDC *($/BOE)*	**12.89**	**19.43**	**-34%**	**19.32**
Operating netback *($/BOE)*	**25.00**	**34.92**	**-28%**	**31.40**
Recycle ratio – proved	**1.9**	**1.8**	**6%**	**1.6**
Proved plus Probable Reserves				
Capital expenditures *($ 000's)*	148,761	183,477	-19%	936,635
Change in FDC costs required to develop reserves *($ 000's)*	(30,697)	103,608	–	145,017
Total capital costs *($ 000's)*	118,064	287,085	-59%	1,081,652
Reserve additions, net *(mBOE)*	11,997	23,457	-49%	77,956
FD&A cost, before FDC *($/BOE)*	12.40	7.82	59%	12.01
FD&A cost, including FDC *($/BOE)*	**9.84**	**12.24**	**-20%**	**13.88**
Operating netback *($/BOE)*	**25.00**	**34.92**	**-28%**	**31.40**
Recycle ratio – proved plus probable	**2.5**	**2.9**	**-14%**	**2.3**

FD&A COST
($/BOE) 2005 – 2009

Celtic's 2009 capital investment program resulted in net reserve additions that replaced 2009 production by a factor of 2.2 (3.0 in 2008) times on a proved basis and 2.3 (5.8 in 2008) times on a proved plus probable basis.

The following table summarizes production replacement for 2009:

PRODUCTION REPLACEMENT	Proved			Proved plus Probable		
Year ended December 31, 2009	Oil mbbls	Gas mmcf	Combined mBOE	Oil mbbls	Gas mmcf	Combined mBOE
Reserve additions, including revisions	1,881	57,267	11,426	2,016	59,888	11,997
2009 Production	1,346	23,005	5,180	1,346	23,005	5,180
Production replacement ratio	**1.4**	**2.5**	**2.2**	**1.5**	**2.6**	**2.3**

Net Asset Value

Celtic's net asset value at December 31, 2009 increased to $946.1 million, up 12% from $844.7 million at December 31, 2008. On a per share basis, net asset value increased by 4% to $19.76 per share compared to $18.97 per share at December 31, 2008. The present value of petroleum and natural gas ("P&NG") reserves were determined by Sproule in their year-end evaluation report. The present value of P&NG reserves is determined using a discount rate of 10% before tax. Undeveloped land at December 31, 2009 was valued at an average price of $192 per acre compared to $196 per acre at December 31, 2008. Proceeds from exercise of stock options are based on average exercise prices of $13.90 per share at December 31, 2009 and $12.96 per share at December 31, 2008.

The components of net asset value are summarized in the following table:

NET ASSET VALUE	At December 31, 2009	At December 31, 2008	
	Forecast Prices 10% Discount Rate $ 000's	Forecast Prices 10% Discount Rate $ 000's	Percent Change
Present value of P&NG reserves, discounted, before tax	1,011,939	891,048	14%
Undeveloped land	56,582	48,339	17%
Bank debt, net of working capital	(168,417)	(136,595)	23%
Proceeds from exercise of stock options	45,967	41,865	10%
Net asset value	**946,071**	**844,657**	**12%**
Diluted common shares outstanding *(thousands)*	47,871	44,536	7%
Net asset value per share *($/share)*	**19.76**	**18.97**	**4%**

NET ASSET VALUE PER SHARE
($/Share) 2005 – 2009

CAPITAL RESOURCES AND LIQUIDITY

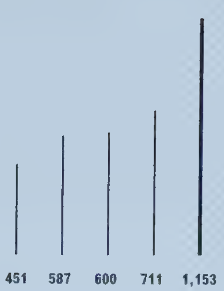
Market Capitalization

The Company's total capitalization increased 62% to $1,153.1 million at December 31, 2009. Market value of common shares represented 80% of total capitalization, while debt, including working capital represented 15% of total capitalization. The following table summarizes the Company's capitalization:

CAPITALIZATION	At December 31, 2009		At December 31, 2008		
($ 000's, except per share amounts)	$ 000's	Ratio	$ 000's	Ratio	Percent Change
Common shares outstanding *(000's)*	44,563		41,306		8%
Share price *(last price traded at in the year)*	20.89		12.61		66%
Market capitalization	930,921	80%	520,869	73%	79%
Bank debt, net of working capital	168,417	15%	136,595	19%	23%
Asset retirement obligation	6,588	1%	5,834	1%	13%
Future income tax liability	47,203	4%	47,604	7%	-1%
Total capitalization	**1,153,129**	**100%**	**710,902**	**100%**	**62%**

At December 31, 2009, the Company had $173.9 million outstanding on its credit facility. Net debt, including working capital surplus was $168.4 million, representing approximately 1.4 times 2009 funds from operations and approximately 0.9 times forecasted 2010 funds from operations.

KEY DEBT RATIOS	At December 31, 2009		At December 31, 2008		
	$ 000's	Ratio	$ 000's	Ratio	Percent Change
Debt to funds from operations ratio:					
Total debt	168,417		136,595		23%
Funds from operations	118,025		131,360		-10%
Funds from operations – 2010 forecast	190,000				
Debt to funds from operations – trailing		1.4		1.0	40%
Debt to funds from operations – forward		**0.9**		**1.2**	**-25%**
Asset coverage ratio:					
Total assets	678,770		649,654		4%
Total debt	168,417		136,595		23%
Asset coverage		**4.0**		**4.8**	**-17%**
Debt to equity ratio:					
Total debt	168,417		136,595		23%
Shareholders' equity	387,190		367,808		5%
Debt/equity		**0.4**		**0.4**	**0%**



CAPITALIZATION
($ Millions) 2005 – 2009

Source of Funds

Investment funding for capital expenditures incurred in 2009 was provided by proceeds from equity issues, bank debt and cash provided by operating activities.

In April 2009, the Company issued 2.8 million common shares by way of a short-form prospectus, at an issue price of $13.25 per share, resulting in gross proceeds of $36.4 million. During the year, upon exercise of stock options, Celtic also issued 0.5 million common shares at an average price of $10.28 per share for proceeds of $5.2 million.

In April 2008, the Company issued 2.9 million common shares by way of a short-form prospectus, at a price of $15.00 per share, resulting in gross proceeds of $43.1 million. During the year, upon exercise of stock options, Celtic also issued 0.8 million common shares at an average price of $7.34 per share for proceeds of $5.6 million.

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada. The authorized borrowing amount under this facility as at December 31, 2009 is $215.0 million. An interim review was conducted by the financial institutions effective September 30, 2009 and the borrowing base amount of $215.0 million was re-confirmed. The facilities are available for a period of 364 days, maturing on June 29, 2010 and may be extended for an additional 364 days. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Covenants include a current ratio test, reporting requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. As at December 31, 2009, the Company is in compliance with all covenants. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

At December 31, 2009, Celtic had drawn $173.9 million, leaving sufficient unused credit lines available to fund on-going capital expenditures. In order to fund all capital expenditures incurred in 2009, the Company augmented its equity issues and bank borrowings by generating $103.7 million in cash provided by operating activities for the year ended December 31, 2009.

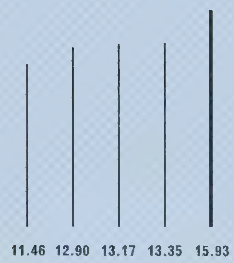
Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

Working Capital

The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At December 31, 2009, the working capital amount including outstanding bank debt represented 78% of the Company's maximum authorized bank borrowing credit limit.

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas. This occurs on the 25th day following the month of sale. As a result, the Company's production revenues are collected in an orderly fashion. Celtic monitors its revenue counterparty credit positions to mitigate any potential credit losses. To the extent that the Company has joint venture partners in its activities, it must collect the partners' share of capital expenditures and operating expenses on a monthly basis. Exceptions are in the event that the partners' share of a capital project is a significant amount. In this case, Celtic will collect such amounts from its partners in advance of expenditures taking place in accordance with standard industry operating procedures. At December 31, 2009, the Company did not have any material accounts receivable that were deemed uncollectible, except as noted below.

Celtic has expensed $31.2 million ($13.2 million in 2009 and $18.0 million in 2008) as a provision for non-recoverable accounts receivable relating to a total financial exposure of approximately $32.5 million. The exposure was created with the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the *Companies' Creditors Arrangement Act Canada ("CCAA")* in the Court of Queen's Bench of Alberta Judicial District of Calgary. The total amount of the financial exposure primarily relates to the Company's natural gas and associated by-product sales to SemCAMS during the period from June 1, 2008 to July 21, 2008.



AVERAGE STOCK TRADING PRICE
($/Share) 2005 – 2009

Accounts payable consist of amounts payable to suppliers relating to head office and field operating and investing activities. These invoices are processed within the Company's normal payment period.

Celtic actively manages the pace of its capital spending program by monitoring forecasted production and commodity prices and resulting cash flows. Should circumstances affect cash flow in a detrimental way, the Company is capable of reducing capital investment levels.

Liquidity

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2008 and 2009, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets.

The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

Share Information

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at December 31, 2009, there were 44.6 million common shares outstanding (as at March 3, 2010, there were 44.7 million common shares outstanding). There are no preferred shares outstanding.

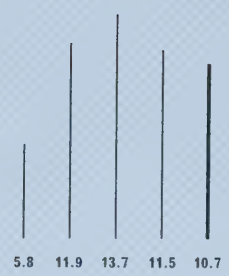
As at December 31, 2009, directors, employees and certain consultants have been granted options to purchase 3.3 million common shares of the Company at an average exercise price of $13.90 per share. Detailed information regarding the Company's stock options outstanding is contained in the notes to the financial statements.

The Company's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "CLT". During 2009, 40.4 million shares traded on the TSX at an average price of $15.93 per share. These volumes were 14% higher than the 35.5 million shares traded in 2008 at an average price of $13.35 per share.

The following table outlines Celtic's common share trading activity by quarter during the years 2009 and 2008:

SHARE TRADING ACTIVITY (CLT)	Q1	Q2	Q3	Q4	2009
High *($)*	14.50	17.20	19.46	21.50	**21.50**
Low *($)*	10.52	13.00	13.11	17.55	**10.52**
Close *($)*	13.73	15.25	19.10	20.89	**20.89**
Volume traded *(thousands)*	9,812	11,795	7,588	11,175	**40,370**
Value traded *($ 000's)*	125,142	175,359	123,512	219,005	**643,018**
Weighted average trading price *($)*	12.75	14.87	16.28	19.60	**15.93**

	Q1	Q2	Q3	Q4	2008
High *($)*	15.85	21.05	20.18	14.00	21.05
Low *($)*	10.99	15.00	11.66	9.19	9.19
Close *($)*	15.48	19.77	14.08	12.61	12.61
Volume traded *(thousands)*	4,974	6,384	7,390	16,713	35,461
Value traded *($ 000's)*	67,194	114,831	111,134	180,388	473,547
Weighted average trading price *($)*	13.51	17.99	15.04	10.79	13.35



AVERAGE DEBT OUTSTANDING PER BOE/D
($ Thousands per BOE/D) 2005 – 2009

Future Commitments – Financial Instruments

The Company may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, currency exchange and interest rates in order to secure a certain amount of cash flow to protect a desired level of capital spending.

The following is a summary of NYMEX-AECO fixed natural gas basis differential derivative contracts in effect as at December 31, 2009:

Daily Quantity	Remaining Term of Contract	Fixed Price per mmbtu
50,000 mmbtu/d	January 1 to March 31, 2010	US$0.64
50,000 mmbtu/d	April 1 to December 31, 2010	US$0.68

The Company has entered into currency average rate forward swap transactions whereby U.S. dollars have been converted to Canadian dollars as summarized in the following table:

Amount	Remaining Term of Contract	Fixed Exchange Rate (CAD/USD)
US$4,000,000/month	January 1 to December 31, 2010	1.2106

The following is a summary of interest rate swap contracts that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate, in effect as at December 31, 2009:

Amount	Remaining Term of Contract	Fixed Interest Rate
CA$80,000,000	January 1, 2010 to April 22, 2010	3.30%
CA$20,000,000	January 1, 2010 to April 22, 2010	2.54%
CA$100,000,000	April 22, 2010 to April 21, 2011	2.07%

Contractual Obligations

Celtic has a committed term credit facility with certain financial institutions. At December 31, 2009, the Company had bank debt outstanding in the amount of $173.9 million. The authorized borrowing amount available under the term credit facility is $215.0 million and is available on a revolving basis until June 29, 2010. Commencing on June 29, 2010, the Company may request the facility be available on a non-revolving basis for a period of one year thereafter, subject to approval by lenders with commitments of at least two thirds of the credit facility amount.

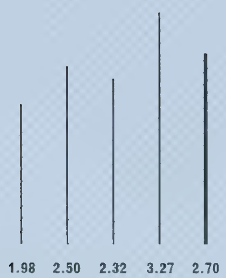
From time to time, the Company enters into agreements to transport and market oil and gas production. In addition, the Company has entered into agreements with third parties that provides employees with access to specialized computer software and information including production and reserves data, geological data, accounting systems and land management systems.

As a normal course of business, the Company leases office space, vehicles for field personnel and office equipment such as computers, printers and photocopiers. The Company is committed to future payments under the following agreements:

CONTRACTUAL OBLIGATIONS

($ 000's)	2010	2011	2012	2013	Total
Operating lease – office building	$ 598	$ 200	–	–	$ 798
Operating lease – vehicles	101	36	–	–	137
Firm transportation agreements	53	28	–	–	81
Total	**$ 752**	**$ 264**	**–**	**–**	**$ 1,016**

Office building operating lease relates to rental office space in Calgary, Alberta which expires on April 30, 2011.



FUNDS FROM OPERATIONS PER SHARE (DILUTED)
($/Share) 2005 – 2009

Related Party and Off–Balance Sheet Transactions

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During 2009, the Company incurred $0.3 million (2008 - $0.4 million) in legal fees and disbursements with BLG. The Company expects to continue using the services of this law firm from time to time.

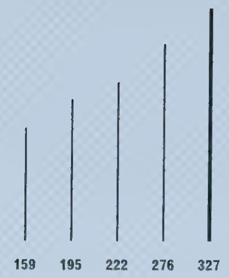
Celtic was not involved in any off-balance sheet transactions in the years ended December 31, 2008 and 2009.

SUPPLEMENTAL QUARTERLY INFORMATION

The Company has been successful in providing strong growth in funds from operations and oil and gas production. The following tables summarize key financial and operating information by quarter:

QUARTERLY FINANCIAL INFORMATION

($ 000's, except per share amounts)	Q1	Q2	Q3	Q4	Annual
2009					
Revenue, before royalties and financial instruments	41,435	30,668	40,364	60,146	**172,613**
Funds from operations	28,140	20,008	27,874	42,003	**118,025**
Funds from operations per share - basic	0.68	0.46	0.63	0.94	**2.72**
Funds from operations per share - diluted	0.68	0.46	0.62	0.93	**2.70**
Net earnings (loss)	(5,039)	(5,459)	(13,666)	906	**(23,258)**
Earnings (loss) per share - basic	(0.12)	(0.13)	(0.31)	0.02	**(0.54)**
Earnings (loss) per share - diluted	(0.12)	(0.13)	(0.31)	0.02	**(0.54)**
Capital expenditures, net	41,583	36,619	29,040	41,519	**148,761**
Total assets	658,765	663,531	657,919	678,770	**678,770**
Bank debt, net of working capital	160,974	145,976	159,319	168,417	**168,417**
2008					
Revenue, before royalties and financial instruments	57,371	80,220	73,904	51,842	263,337
Funds from operations	28,298	36,787	34,226	32,049	131,360
Funds from operations per share - basic	0.75	0.92	0.83	0.78	3.28
Funds from operations per share - diluted	0.74	0.90	0.83	0.78	3.27
Net earnings (loss)	(7,375)	(9,116)	31,145	29,585	44,239
Earnings (loss) per share - basic	(0.20)	(0.23)	0.76	0.72	1.10
Earnings (loss) per share - diluted	(0.20)	(0.23)	0.75	0.72	1.10
Capital expenditures, net	32,608	67,736	40,359	42,774	183,477
Total assets	511,705	572,691	594,672	649,654	649,654
Bank debt, net of working capital	157,412	156,483	146,211	136,595	136,595



PRODUCTION PER MILLION SHARES
(BOE/D) 2005 – 2009

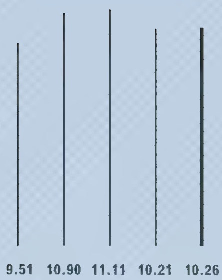
QUARTERLY OPERATING INFORMATION	Q1	Q2	Q3	Q4	Annual
2009					
Production					
Oil *(bbls/d)*	3,601	2,939	3,813	4,384	**3,687**
Natural gas *(mcf/d)*	57,706	47,822	68,964	77,339	**63,028**
Combined *(BOE/d)*	13,219	10,909	15,307	17,274	**14,192**
Production per million shares *(BOE/d)*	320	251	346	388	**327**
Realized sales prices, after financial instruments					
Oil *($/bbl)*	79.01	86.32	79.71	80.22	**81.00**
Natural gas *($/mcf)*	5.36	3.77	3.39	4.86	**4.36**
Combined *($/BOE)*	44.54	39.78	35.11	42.17	**40.43**
Operating netbacks, after financial instruments					
Oil *($/bbl)*	50.32	60.85	57.88	58.66	**56.87**
Natural gas *($/mcf)*	2.74	1.52	1.67	3.01	**2.30**
Combined *($/BOE)*	25.29	23.06	21.94	28.42	**25.00**
2008					
Production					
Oil *(bbls/d)*	3,309	3,367	3,386	3,554	3,404
Natural gas *(mcf/d)*	38,717	44,852	49,310	51,029	46,000
Combined *(BOE/d)*	9,762	10,842	11,604	12,059	11,071
Production per million shares *(BOE/d)*	259	270	282	293	276
Realized sales prices, after financial instruments					
Oil *($/bbl)*	81.17	90.48	90.28	68.63	82.45
Natural gas *($/mcf)*	8.51	9.52	8.28	7.36	8.37
Combined *($/BOE)*	61.26	67.49	61.51	51.30	60.12
Operating netbacks, after derivatives					
Oil *($/bbl)*	44.02	48.96	46.41	42.60	45.46
Natural gas *($/mcf)*	5.07	5.97	4.87	4.39	5.04
Combined *($/BOE)*	35.02	39.94	34.20	31.03	34.92

The majority of Celtic's production growth has been the result of the Company's successful exploration and development drilling activities. The Company estimates that over 80% of fourth quarter 2009 production came from exploration and development activities and the balance from acquisitions.

In addition to drilling activities, oil and gas property acquisitions completed in 2008 have also contributed to production growth. In 2008, Celtic completed the acquisition of complementary liquids-rich natural gas properties in the Kaybob South area of west central Alberta for approximately $44.9 million, adding approximately 928 BOE/d (68% natural gas and 32% natural gas liquids) at the time of the acquisition.

BUSINESS RISKS

Celtic's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers, intermediate and senior producers and royalty trust organizations, to the much larger integrated petroleum companies. Celtic is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in



PRODUCTION EXPENSE PER BOE
($/BOE) 2005 – 2009

commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Celtic employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Celtic explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Celtic has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Celtic strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Celtic does not operate.

Celtic is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Celtic may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Celtic utilizes bank financing to support on-going capital investment. Funds from operations also provide Celtic with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

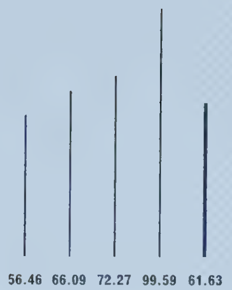
Safety and Environment

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Celtic maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

Climate Change

The Federal Government has announced its intention to regulate greenhouse gases ("GHG") and other air pollutants. As these regulations are under development, the Company is unable to predict the total impact of the potential regulations upon its business. The Alberta Government has set targets for GHG emission reductions. In order to comply with the Alberta regulations, companies can make operating improvements to its facilities, purchase carbon offsets or make a monetary contribution to the Alberta Climate Change and Emissions Management Fund.

Celtic has applied to the Energy Resources Conservation Board ("ERCB") to make modifications to its existing sour gas processing facility located at Kaybob. The Company believes that these modifications will result in significant reductions in GHG emissions and is confident that the ERCB will approve the Company's application. If approved, Celtic expects to spend approximately $35.0 million in capital expenditures that will result in a gas processing capability of handling 150 MMCF per day of raw gas. In addition to reductions in GHG emissions, Celtic will benefit with lower overall processing costs for the majority of its natural gas production at Kaybob, Alberta.



WTI OIL PRICES
(US$/BBL) 2005 – 2009

BUSINESS OUTLOOK

Advisory Regarding Forward–Looking Statements

Certain information with respect to Celtic contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, certain of which are beyond Celtic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Celtic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. In addition, the reader is cautioned that historical results are not necessarily indicative of future performance.

Current Economic Environment

Late in 2008 and early in 2009, the financial community around the world was rocked with unprecedented losses and business failures. The recovery has been slow and as a result, the current economic environment is challenging and uncertain. Celtic expects to see an improving economic environment in 2010, with improving commodity prices, less volatile financial markets and better access to capital markets.

In this environment, Celtic has maintained financial flexibility through the prudent use of bank debt and through an active risk management strategy whereby cash flow for 2009 was secured to a certain extent through the use of commodity price, currency and interest rate financial instruments.

Celtic's capital expenditure program remains flexible and if the current economic environment continues to deteriorate, the Company has the ability to defer expenditures into the future.

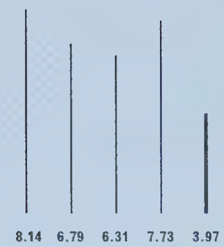
2010 Guidance

Celtic continues to remain optimistic about its future prospects. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high quality product stream that on a historical basis receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone hydrocarbon potential.

Celtic's Board of Directors has approved a capital expenditure budget in the amount of $187.0 million for 2010. The capital budget will be increased by $35.0 million if the Company obtains approval from the ERCB to build its proposed gas processing facility at Kaybob. Capital expenditures will be reduced by drilling royalty credits earned during 2010 in the amount of $20.0 to $25.0 million. Capital spending for 2010 is expected to be financed by funds from operations, disposition of certain assets located at Swan Hills, Alberta for proceeds of $53.2 million, access to available bank credit lines and common share issuances, if necessary.

After forecasting risked production discoveries, timing of production on-stream dates resulting from the Company's planned capital expenditures for 2010, estimated decline rates on existing and new volumes, Celtic expects production in 2010 to average between 18,500 and 18,700 BOE/d (19% oil and 81% gas). This represents between a 30% and 32% increase from the average production of 14,192 BOE/d achieved in 2009. Celtic expects to exit 2010 with production in excess of 20,000 BOE/d.

Financial turmoil and the global recession which frequented news headlines in recent months may now be starting to stabilize with expectations of a global economic recovery in 2010. As a result, Celtic expects oil prices to be higher in 2010 compared to 2009. Industrial demand for natural gas in North America is also expected to increase with a recovering economy, while at the same time, natural gas supply in the United States may shrink given the lower number of rigs actively drilling for natural gas compared to a year ago. Both these factors will likely result in higher natural gas prices in 2010 compared to 2009.



AECO GAS PRICES
($/GJ) 2005 2009

The Company's average commodity price assumptions for 2010 are US$72.50 per barrel for WTI oil, US$6.50 per MMBTU for NYMEX natural gas, $5.75 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US$0.952. These prices compare to average 2009 prices of US$61.63 per barrel for WTI oil, US$4.01 per MMBTU for NYMEX natural gas, $3.97 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US$0.880.

After giving effect to the aforementioned production and commodity price assumptions and taking into effect commodity risk price management contracts in place (as outlined under Future Commitments above), funds from operations for 2010 is forecasted to be approximately $170.0 million or $3.82 per share ($3.74 per share, diluted) and net earnings are forecasted to be approximately $23.0 million or $0.52 per share ($0.51 per share, diluted).

Changes in forecasted commodity prices and variances in production estimates can have a significant impact to estimated funds from operations and net earnings. Please refer to the advisory regarding forward-looking statements shown above.

Bank debt, net of working capital, is estimated to be $109.2 million by the end of 2010 or approximately 0.6 times forecasted 2010 funds from operations. If the gas processing facility at Kaybob is approved and constructed in 2010, bank debt, net of working capital would increase to $144.2 million or approximately 0.8 times forecasted 2010 funds from operations.

Celtic's capital expenditure budget for 2010 will see the Company participate at high working interests in the drilling of approximately 55 to 60 wells during the year, of which approximately 85% will be horizontal wells. Celtic continues to evaluate and pursue potential property acquisitions that would complement its existing asset base and completion of such acquisitions would be over and above the Company's planned capital expenditure budget.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per share growth in production, reserves, net asset value and funds from operations. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2010 and beyond.

The information set out herein under the heading "2010 Guidance" is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Celtic's reasonable expectations as to the anticipated results of its proposed business activities for 2010. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

ADDITIONAL INFORMATION

Additional information relating to Celtic, including the Company's Annual Information Form ("AIF") is filed on SEDAR and can be viewed on their website at www.sedar.com. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer at Celtic Exploration Ltd., Suite 500, 505 Third Street SW, Calgary, Alberta, Canada, T2P 3E6. Further information relating to the Company is also available on its website at www.celticex.com.

FINANCIAL STATEMENTS

CELTIC EXPLORATION LTD.

MANAGEMENT'S REPORT

Management has prepared the accompanying financial statements of Celtic Exploration Ltd. in accordance with Canadian generally accepted accounting principles. Financial information presented throughout this annual report is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial information. Where appropriate, management has made informed judgments and estimates in accounting for transactions which affect the current accounting period but cannot be finalized with certainty until future periods. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

PricewaterhouseCoopers LLP was appointed by the Company's shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of Celtic's internal control systems and included such tests and procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. This Committee, consisting of nonmanagement directors, meets with management and independent auditors to ensure that each group is properly discharging its responsibilities and to discuss adequacy of internal controls, accounting policies and financial reporting matters. The Audit Committee has reviewed the financial statements and has reported thereon to the Board of Directors. The Board has approved the financial statements for issuance to the shareholders.

David J. Wilson
President and Chief Executive Officer
March 3rd, 2010

Sadiq H. Lalani
Vice President, Finance and Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Celtic Exploration Ltd.

We have audited the balance sheets of Celtic Exploration Ltd. as at December 31, 2009 and 2008, and the statements of earnings, retained earnings and accumulated other comprehensive income, and cash flows for the years ended December 31, 2009 and 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008, and the results of its operations and its cash flows for the years ended December 31, 2009 and 2008, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
March 3rd, 2010

BALANCE SHEET

($ 000's)		As at December 31, 2009	As at December 31, 2008
Assets			
Current assets			
Cash and cash equivalents		$ 42	$ 73
Accounts receivable		49,252	50,728
Drilling royalty credits	[Note 3]	13,158	0
Prepaid expenses and deposits		4,947	4,010
Fair value of financial instruments	[Note 10]	1,463	36,154
Future income tax asset		510	848
		69,372	91,813
Other assets	[Note 1]	6,090	3,282
Property, plant and equipment	[Note 2]	603,308	554,559
		$ 678,770	$ 649,654
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		$ 61,708	$ 64,548
Fair value of financial instruments	[Note 10]	1,757	2,925
Future income tax liability		424	10,485
Bank debt	[Note 4]	173,900	150,450
		237,789	228,408
Asset retirement obligation	[Note 5]	6,588	5,834
Future income tax liability	[Note 7]	47,203	47,604
		$ 291,580	$ 281,846
Shareholders' Equity			
Share capital	[Note 6]	$ 282,990	$ 241,673
Contributed surplus	[Note 6]	5,300	3,977
Retained earnings and accumulated other comprehensive income		98,900	122,158
		$ 387,190	$ 367,808
		$ 678,770	$ 649,654

Commitments [Note 9]

Contingencies [Note 13]

The accompanying notes form an integral part of these financial statements.

On behalf of the Board of Directors:

Director

Director

STATEMENT OF OPERATIONS

($ 000's, except per share amounts)		Twelve months ended December 31, **2009**	2008
Revenue			
Oil and gas		**$ 172,613**	$ 263,337
Royalties		**(22,968)**	(58,449)
Realized gain (loss) on financial instruments		**34,294**	(19,766)
Unrealized gain (loss) on financial instruments		**(33,523)**	32,304
		$ 150,416	$ 217,426
Expenses			
Production		**$ 53,123**	$ 41,376
Transportation		**3,819**	2,314
Interest and financing		**5,025**	6,122
General and administrative		**3,947**	3,950
Stock based compensation	*[Note 6 (d)]*	**2,362**	1,858
Provision for non-recoverable accounts receivable	*[Note 10 (b)]*	**13,233**	17,986
Depletion, depreciation and accretion	*[Note 2]*	**101,808**	85,586
		$ 183,317	$ 159,192
Earnings (loss) before taxes		**$ (32,901)**	$ 58,234
Provision for (recovery of) future income taxes	*[Note 7]*	**(9,643)**	13,995
Net earnings (loss) and comprehensive income (loss)		**$ (23,258)**	$ 44,239
Earnings (loss) per share			
Basic		**$ (0.54)**	$ 1.10
Diluted	*[Note 8]*	**(0.54)**	1.10

STATEMENT OF RETAINED EARNINGS AND ACCUMULATED OTHER COMPREHENSIVE INCOME

($ 000's)	Twelve months ended December 31, **2009**	2008
Retained earnings and accumulated other comprehensive income, beginning of period	**$ 122,158**	$ 77,919
Net earnings (loss) and comprehensive income (loss)	**(23,258)**	44,239
Retained earnings and accumulated other comprehensive income, end of period	**$ 98,900**	$ 122,158

The accompanying notes form an integral part of these financial statements.

STATEMENT OF CASH FLOWS

($ 000's)		Twelve months ended December 31, 2009	2008
Operating activities			
Net earnings (loss)		$ (23,258)	$ 44,239
Items not affecting cash:			
Depletion, depreciation and accretion		101,808	85,586
Provision for non-recoverable accounts receivable		13,233	17,986
Stock based compensation		2,362	1,858
Unrealized loss (gain) on financial instruments		33,523	(32,304)
Provision for (recovery of) future income taxes		(9,643)	13,995
		$ 118,025	$ 131,360
Settlement of asset retirement obligations		(1,043)	(806)
Change in non-cash operating working capital	[Note 11]	(13,261)	(41,300)
Cash provided by operating activities		$ 103,721	$ 89,254
Financing activities			
Increase in bank debt		$ 23,450	$ 30,550
Issue of common shares, net of costs		39,798	46,623
Cash provided by financing activities		$ 63,248	$ 77,173
Investing activities			
Property, plant and equipment expenditures		$ (146,964)	$ (138,396)
Property, plant and equipment acquisitions		(2,172)	(49,406)
Property, plant and equipment dispositions		375	4,325
Change in other assets		(2,808)	1,000
Change in non-cash investing working capital	[Note 11]	(15,431)	13,041
Cash used in investing activities		$ (167,000)	$ (169,436)
Net change in cash and cash equivalents		$ (31)	$ (3,009)
Cash and cash equivalents, beginning of period		73	3,082
Cash and cash equivalents, end of period		$ 42	$ 73

The accompanying notes form an integral part of these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2009 and December 31, 2008
(All tabular amounts in thousands, unless otherwise stated)

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of business

Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated under the *Business Corporations Act* (Alberta) on April 16, 2002. Celtic is an oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in Western Canada, primarily in Alberta.

Basis of presentation

These financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements as well as the reported amounts of revenues, expenses and cash flows during the period. Actual results could differ from these estimates.

Measurement uncertainty

The amounts recorded for the fair value of financial instruments, stock based compensation, depletion, depreciation and accretion of assets, the provision for asset retirement obligation costs and the provision for future income taxes are based on estimates. In addition, the ceiling test calculation is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Joint interests

A substantial portion of the Company's exploration, development and production activities is conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, demand deposits and investments in highly liquid money market instruments which are convertible to known amounts of cash in less than three months.

Financial instruments and derivatives

GAAP prescribes when a financial asset, financial liability or non-financial derivative is to be recognized on the balance sheet and at what amount, requiring fair value or cost-based measures under different circumstances. All financial instruments must be classified as one of the following five categories: loans and receivables; held-to-maturity investments; held-for-trading instruments; available-for-sale financial assets; or other financial liabilities. All financial instruments, with the exception of loans and receivables, held-to-maturity investments and other financial liabilities which are recorded at amortized cost, are reported on the balance sheet at fair value. Subsequent measurement and changes in fair value will depend on their initial classification. Available-for-sale financial assets are measured at fair value and unrealized gains or losses resulting from changes in fair value are recorded in other comprehensive income until the investment is de-recognized or impaired at which time the amounts would be recorded in earnings.

All derivative instruments, including embedded derivatives, are recorded on the balance sheet at fair value unless they qualify for the normal sale and purchase exception. All changes in fair value are included in earnings unless cash flow hedge or net investment accounting is used, in which case changes in fair value are recorded in other comprehensive income, to the extent the hedge is effective, and in earnings, to the extent it is ineffective.

Other assets

Other assets are comprised mainly of oilfield equipment, well tubing and casing inventory. Oilfield equipment is valued at cost. Well tubing and casing inventory is valued at weighted average cost.

Property, plant and equipment

The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, production equipment and facilities, carrying costs directly related to unproved properties and costs related to acquisition of petroleum and natural gas assets directly or by means of a

business combination. These capitalized costs along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted on a unit of production basis using estimated proved petroleum and natural gas reserves as evaluated by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion until it is determined whether proved reserves are attributable to the properties or impairment occurs.

Gains or losses on the disposition of properties are not recognized unless the proceeds on disposition result in a change of 20 percent or more in the depletion rate.

Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25 percent.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from undiscounted future net cash flows based on proved reserves, which are determined by using forecasted future prices, plus unproved properties. If the carrying amount exceeds the ultimate recoverable amount, an impairment loss is recognized in net earnings. The impairment loss is limited to the amount by which the carrying amount exceeds: (i) the sum of the fair value of proved and probable reserves; and (ii) the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Asset retirement obligations

Estimated future costs relating to retirement obligations associated with oil and gas well sites and facilities are recognized as a liability, at fair value at the time when the liability is incurred. The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion. The liability is adjusted at each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability.

Future income taxes

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Flow–through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as a future income tax liability and a reduction in share capital, at the time the renunciation documents are filed with the appropriate tax authorities.

Revenue recognition

Revenue from the sale of oil, natural gas and associated by-products is recorded when title passes to a third party and collectibility is reasonably assured.

Stock–based compensation

The Company has a stock-based compensation plan and uses the fair-value method to record compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant and a provision for the costs is provided for as contributed surplus over the vesting period outlined in the option agreement. The consideration received by the Company on the exercise of share options is recorded as an increase to share capital together with corresponding amounts previously recognized in contributed surplus. Forfeitures are accounted for as they occur which could result in recoveries of the compensation expense.

Comprehensive income

Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources and other comprehensive income comprises revenues, expenses, gains and losses that, in accordance with GAAP, are recognized in comprehensive income but excluded from net earnings.

Per share amounts

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period.

Diluted per share amounts are calculated using the treasury stock method which assumes that any proceeds obtained on exercise of share options or other dilutive instruments would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

Changes in accounting policies and practices

The following new or revised Canadian Institute of Chartered Accountants ("CICA") Handbook sections became effective January 1, 2009:

Section 3064, *Goodwill and Intangible Assets*; and
Section 3862, *Financial Instruments - Disclosures*.

Section 3064 clarifies the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Adoption of this standard has been applied retroactively and has had no impact on the Company's financial statements.

Section 3862 was revised to include a hierarchy concept in measuring financial instruments, a requirement to provide disclosure concerning the fair value measurements of assets and liabilities for each hierarchy level and amendments to the liquidity disclosure requirements. The impact to the Company's financial statements as a result of adopting this amended standard is reflected in Note 10 of these financial statements.

The following new or revised Canadian Institute of Chartered Accountants ("CICA") Handbook sections became effective July 1, 2009:

Section 1601, *Consolidated Financial Statements*; and
Section 1582, *Business Combinations*.

Section 1601 establishes standards for the preparation of consolidated financial statements. These recommendations are effective January 1, 2011 with early adoption permitted. There is no impact on the Company's financial statements at this time.

Section 1582 establishes principles for the measurement of assets, liabilities and contingencies acquired at fair value, as well as recognizing acquisition-related and reorganization costs separately from the business combination within the statement of operations. These recommendations are effective for business combinations occurring after January 1, 2011, although early adoption is permitted. There is no impact on the Company's financial statements at this time.

2. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated depletion, depreciation and amortization	Net book value
At December 31, 2009			
Oil and gas properties, plant and equipment	$ 953,673	$ 351,200	$ 602,473
Furniture and office equipment	1,743	908	835
Total	$ 955,416	$ 352,108	$ 603,308
At December 31, 2008			
Oil and gas properties, plant and equipment	$ 803,889	$ 250,126	$ 553,763
Furniture and office equipment	1,491	695	796
Total	$ 805,380	$ 250,821	$ 554,559

At December 31, 2009, oil and gas properties with a cost of $39.0 million (December 31, 2008 - $34.5 million) relating to unproved properties have been excluded from the depletion and depreciation calculation. Future capital costs required to develop proved reserves in the amount of $90.5 million (2008 - $92.0 million) are included in the depletion and depreciation calculation.

During the twelve months ended December 31, 2009, the Company capitalized $0.4 million (2008 - $0.4 million) with respect to employee salaries directly relating to exploration and development activities.

As a result of ceiling test calculations at December 31, 2009 and December 31, 2008, the Company was not required to record an impairment loss.

The forecasted future prices used for the next five years in the ceiling test evaluation of the Company's proved reserves as at December 31, 2009 were as follows:

	2010	2011	2012	2013	2014
Oil *($/bbl)*	$ 78.34	$ 83.91	$ 85.37	$ 88.16	$ 89.36
NGLs *($/bbl)*	66.24	71.50	73.95	77.21	79.05
Natural gas *($/mcf)*	5.56	6.48	6.72	7.58	8.39

Prices escalate at varying percentages in a range between 1.7% and 2.4% thereafter.

For comparative purposes the forecasted future prices used for the next five years in the ceiling test evaluation of the Company's proved reserves as at December 31, 2008 were as follows:

	2009	2010	2011	2012	2013
Oil *($/bbl)*	$ 58.97	$ 66.95	$ 73.46	$ 79.76	$ 87.69
NGLs *($/bbl)*	56.41	62.07	68.51	74.20	81.57
Natural gas *($/mcf)*	7.18	7.97	8.28	8.87	9.77

Prices escalate at varying percentages in a range between 1.8% and 2.3% thereafter.

3. DRILLING ROYALTY CREDITS

	2009	2008
Drilling royalty credits, beginning of year	–	–
Credits earned through drilling	$ 20,619	–
Credits claimed	(7,460)	–
Drilling royalty credits, end of year	$ 13,159	–

The Drilling Royalty Credit ("DRC") program introduced by the Alberta government in 2009 provides companies with a $200 per metre credit on wells drilled. These credits can be applied against corporate crown royalties payable during the period from April 1, 2009 to March 31, 2011, subject to a maximum of 50% of corporate crown royalties for Celtic. Credits earned are recorded as a reduction of property, plant and equipment, with reasonable assurance that credits can be claimed in a future period. Since April 1, 2009, Celtic has earned $20.6 million of credits from its drilling activity. At December 31, 2009, $7.5 million has been claimed against corporate crown royalties and $13.2 million remains available to be claimed against future crown royalties payable.

4. BANK DEBT

	December 31, 2009	December 31, 2008
Bank loan	$ 23,900	$ 30,450
Bankers' acceptances	150,000	120,000
Total bank debt	$ 173,900	$ 150,450

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada. The authorized borrowing amount under this facility as at December 31, 2009 is $215.0 million. An interim review was conducted by the financial institutions effective September 30, 2009 and the borrowing base amount of $215.0 million was re-confirmed. The facilities are available for a period of 364 days, maturing on June 29, 2010 and may be extended for an additional 364 days. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Covenants include a current ratio test, reporting requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. As at December 31, 2009, the Company is in compliance with all covenants. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 1.5% to bank prime plus 3.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 2.5% to 4.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times.

The Company has entered into interest rate swap transactions whereby borrowings through bankers' acceptances in the amount of $100.0 million maturing on April 22, 2011 has been fixed at an annual interest rate of 3.2% up to April 22, 2010 and 2.1% from April 22, 2010 to April 21, 2011, before bank stamping fees.

5. ASSET RETIREMENT OBLIGATION

The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

	2009	2008
Asset retirement obligation, beginning of year	$ 5,834	$ 5,719
Liabilities incurred, net of liabilities disposed	225	480
Liabilities settled	(1,043)	(806)
Revisions to estimated liabilities	1,052	(16)
Accretion expense	520	457
Asset retirement obligation, end of year	$ 6,588	$ 5,834

The key assumptions, on which the carrying amount of the asset retirement obligations is based, include a credit-adjusted risk-free rate of 8.5% (2008 - 8.5%) and an inflation rate of 2.7% (2008 - 3.0%). The total undiscounted amount of the estimated cash flows required to settle the obligations is $31.0 million (December 31, 2008 - $27.2 million). The inflated value of estimated cash flows required to settle the obligations at a future period at the time the asset is retired is $81.5 million (December 31, 2008 - $82.2 million). The expected timing of payment of the cash flows required to settle the obligations ranges from 1 year to 51 years.

6. SHARE CAPITAL

(a) Authorized

Unlimited number of common shares and preferred shares.

(b) Issued

The following table summarizes the changes in common shares outstanding for the years ended December 31, 2008 and December 31, 2009:

	Common Shares	Amount
Balance, December 31, 2007	37,666	$ 200,180
Issued for cash on exercise of stock options	766	5,615
Amount relating to exercised options previously recorded as contributed surplus	-	1,245
Issued for cash through public prospectus offering	2,875	43,125
Future income tax benefit transferred on flow-through share issue	-	(6,968)
Share issue costs, after future income taxes	-	(1,524)
Balance, December 31, 2008	41,307	$ 241,673
Issued for cash on exercise of stock options	506	5,205
Amount relating to exercised options previously recorded as contributed surplus	-	1,039
Issued for cash through public prospectus offering	2,750	36,437
Share issue costs, after future income taxes	-	(1,364)
Balance, December 31, 2009	44,563	$ 282,990

(c) Common share offerings

In April 2009, Celtic issued 2.8 million common shares by way of a short form prospectus at an issue price of $13.25 per share for gross proceeds of $36.4 million. In April 2008, Celtic issued 2.9 million common shares by way of a short form prospectus at an issue price of $15.00 per share for gross proceeds of $43.1 million.

(d) Stock options

Celtic has a stock option plan that provides for granting of stock options to directors, officers, employees and certain consultants. Stock options granted under the stock option plan have a maximum term of five years to expiry. Vesting is determined by the Company's board of directors. However, the majority of the options granted vest equally over a three year period commencing on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes the changes in stock options outstanding during the years ended December 31, 2008 and December 31, 2009:

	Number of Options	Average Exercise Price
Balance, December 31, 2007	2,826	$ 10.69
Granted	1,190	14.75
Exercised	(766)	7.34
Forfeited	(21)	13.19
Balance, December 31, 2008	3,229	$ 12.96
Granted	585	15.91
Exercised	(506)	10.28
Forfeited	–	–
Balance, December 31, 2009	3,308	$ 13.90

The Company uses the fair-value method to record stock based compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2009	2008
Risk free interest rate	0.50%	3.07%
Expected life (years)	3.0	3.0
Expected volatility	30%	22%
Expected dividend yield	–	–
Fair value of options granted during the year *($/share)*	3.31	2.78

The following table summarizes information regarding stock options outstanding at December 31, 2009:

Range of exercise prices per share	Number of options outstanding	Weighted average remaining term in years	Weighted average exercise price per share for options outstanding	Number of options exercisable	Weighted average exercise price per share for options exercisable
$10.01 to $12.00	732	1.8	$ 11.66	398	$ 11.51
$12.01 to $14.00	1,275	2.2	12.62	942	12.60
$14.01 to $16.00	615	4.3	15.09	59	14.72
$16.01 to $18.00	558	3.6	17.04	185	17.04
$20.01 to $22.00	128	4.5	19.91	11	20.65
Total	3,308	3.0	$ 13.90	1,595	$ 12.98

(e) Contributed surplus

The following table reconciles the Company's contributed surplus for the years ended December 31, 2009 and December 31, 2008:

	2009	2008
Contributed surplus, beginning of year	$ 3,977	$ 3,364
Stock based compensation expense	2,362	1,858
Amount relating to exercised options	(1,039)	(1,245)
Contributed surplus, end of year	$ 5,300	$ 3,977

7. INCOME TAXES

(a) Future income tax expense

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate as a result of the following:

	2009	2008
Earnings (loss) before taxes	$ (32,901)	$ 58,234
Statutory combined federal & provincial income tax rate	29.00%	29.50%
Expected income taxes (recovery)	$ (9,541)	$ 17,179
Increase (decrease) resulting from:		
Non-deductible stock-based compensation expense	685	548
Benefit relating to changes in future income tax rates	(779)	(3,844)
Other adjustments	(8)	112
Provision for (recovery of) future income taxes	$ (9,643)	$ 13,995

(b) Future income tax liability

The components of future income taxes are as follows:

	December 31, 2009	December 31, 2008
Future income tax liabilities:		
Property, plant and equipment	$ 50,111	$ 50,479
Unrealized financial instrument gains	424	10,485
Future income tax assets:		
Asset retirement obligation costs	(1,647)	(1,458)
Share issue costs	(1,222)	(1,378)
Unrealized financial instrument losses	(510)	(848)
Other income tax assets	(39)	(39)
Net future income tax liability	$ 47,117	$ 57,241
Net current portion	86	(9,637)
Future income taxes - non-current	$ 47,203	$ 47,604

8. EARNINGS PER SHARE

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under this method, only "in-the-money" dilutive instruments impact the calculations in computing diluted earnings per share.

In computing diluted earnings per share, 0.3 million (2008 - 0.1 million) shares were added to the 43.4 million (2008 - 40.0 million) weighted average number of common shares outstanding during the twelve month period for the dilutive effect of stock options. For the purpose of calculating the diluted net loss per share for the year ended December 31, 2009, the incremental shares from assumed exercise of stock options are not included due to their anti-dilutive effect.

9. COMMITMENTS

The Company is committed to future payments under the following agreements:.

	2010	2011	2012	2013	Total
Operating lease – office building	$ 598	$ 200	–	–	$ 798
Operating lease – vehicles	101	36	–	–	137
Firm transportation agreements	53	28	–	–	81
	$ 752	$ 264	–	–	$ 1,016

Office building operating lease relates to rental office space in Calgary, Alberta which expires on April 30, 2011.

At December 31, 2009, the Company had bank debt outstanding in the amount of $173.9 million. The Company has a $215.0 million term credit facility that is available on a revolving basis until June 29, 2010. Commencing on June 29, 2010, the Company may request the facility be available on a non-revolving basis for a period of one year thereafter, subject to approval by lenders with commitments of at least two thirds of the credit facility amount.

10. FINANCIAL INSTRUMENTS

(a) Fair values of financial assets and liabilities

Financial instruments of the Company consist mainly of cash and cash equivalents, deposits, drilling royalty credits, receivables, payables, bank debt and assets and liabilities arising from the use of financial instrument risk management contracts, all of which are included in these financial statements.

Effective January 1, 2009, the Company adopted revisions to CICA Handbook Section 3862 whereby a hierarchy concept in measuring financial instruments and a requirement to provide disclosure concerning the fair value measurements of assets and liabilities for each hierarchy level is to be included in its financial statements. The following table presents the Company's fair value measurements for each hierarchy level as at December 31, 2009:

	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs	Total
Cross currency swaps	–	$ 7,238	–	$ 7,238
Natural gas basis swaps	–	(5,775)	–	(5,775)
Interest rate swaps	–	(1,757)	–	(1,757)
Net asset (liability)	–	$ (294)	–	$ (294)

At December 31, 2009, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying Amount	Fair Value
Receivables and other financial assets		
(accounts receivable, drilling royalty credits and deposits)	$ 68,579	$ 68,579
Held-for-trading instruments (financial instruments and cash)	(252)	(252)
Other financial liabilities (accounts payable and bank debt)	(237,674)	(237,674)
Total	$ (169,347)	$ (169,347)

At December 31, 2008, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying Amount	Fair Value
Receivables and other financial assets		
(accounts receivable, drilling royalty credits and deposits)	$ 54,054	$ 54,054
Held-for-trading instruments (financial instruments and cash)	33,302	33,302
Other financial liabilities (accounts payable and bank debt)	(214,998)	(214,998)
Total	$ (127,642)	$ (127,642)

(b) Credit risk

The majority of the Company's accounts receivable is in respect of oil and gas operations. Celtic generally extends unsecured credit to these third parties, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk.

The ageing of the Company's accounts receivable as at December 31, 2009 is summarized in the following table:

December 31, 2009	Current	31 – 60 Days	61 – 90 Days	Over 90 Days	Total
Accounts receivable	$ 42,814	$ 2,293	$ 704	$ 3,441	$ 49,252

Celtic has not experienced any material credit loss in the collection of receivables in 2009 and 2008, except as noted below.

Celtic has expensed $31.2 million ($13.2 million in 2009 and $18.0 million in 2008) as a provision for non-recoverable accounts receivable relating to a total financial exposure of approximately $32.5 million. The exposure was created with the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the Companies' Creditors Arrangement Act Canada ("CCAA") in the Court of Queen's Bench of Alberta Judicial District of Calgary. The total amount of the financial exposure primarily relates to the Company's natural gas and associated by-product sales to SemCAMS during the period from June 1, 2008 to July 21, 2008.

(c) Interest rate risk

The Company is exposed to fluctuations in interest rates on its bank debt. Interest rate risk is mitigated through short-term fixed rate borrowings using bankers' acceptances and interest rate swap transactions.

The Company has entered into interest rate swap transactions whereby the interest rate applicable to borrowings by way of bankers' acceptances has been fixed. Borrowings in the amount of $100.0 million, maturing on April 21, 2011, has been fixed at an annual interest rate of 3.2% up to April 22, 2010 and at an annual rate of 2.1% from April 22, 2010 to April 21, 2011, before bank stamping fees. The fair value of these contracts, mark-to-market at December 31, 2009 is a liability of $1.8 million. If annual interest rates increase (decrease) by 1%, the fair market value of these contracts would increase (decrease) by $1.3 million.

(d) Foreign exchange rate risk

The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices.

The Company has entered into currency average rate forward swap transactions whereby U.S. dollars have been converted to Canadian dollars as summarized in the following table:

Amount	Remaining term of contract	Fixed exchange rate (CAD/USD)
US$4,000,000/month	January 1 to December 31, 2010	1.2106

The fair value of the above currency contracts, mark-to-market at December 31, 2009 is an asset of $7.2 million. If the CAD/USD exchange rate increases (decreases) by CA$0.01 per USD, the fair market value of these contracts would increase (decrease) by $0.5 million.

(e) Commodity price risk management

The following is a summary of NYMEX-AECO fixed natural gas basis differential derivative contracts in effect as at December 31, 2009:

Daily quantity	Remaining term of contract	Fixed price per mmbtu
50,000 mmbtu/d	January 1 to March 31, 2010	US$0.64
50,000 mmbtu/d	April 1 to December 31, 2010	US$0.68

The fair value of the above natural gas contracts, mark-to-market at December 31, 2009 is a liability of $5.8 million. If the NYMEX-AECO basis differential increases (decreases) by US$0.10 per mmbtu, the fair market value of these contracts would increase (decrease) by $1.9 million.

(f) Liquidity risk

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2008 and 2009, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets.

The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

(g) Capital structure

The Company's capital structure is comprised of shareholders' equity, bank debt and working capital. Celtic's objectives when managing its capital structure is to maintain financial flexibility in order to meet financial obligations, as well as to finance future growth through capital expenditures relating to exploration, development and acquisition activities.

The Company monitors its capital structure and short-term financing requirements using a net debt to trailing funds from operations ratio, a non-GAAP financial measure.

	December 31, 2009	December 31, 2008
Bank debt	$ 173,900	$ 150,450
Working capital (surplus) deficiency (1)	(5,691)	9,737
Net debt	$ 168,209	$ 160,187
Trailing funds from operations (2)	$ 168,012	$ 128,196
Net debt to trailing funds from operations ratio	1.00	1.25

(1) *Working capital excludes bank debt and unrealized gains or losses on financial instruments and associated income taxes.*

(2) *Trailing funds from operations is annualized based on the most recent quarter's funds from operations which is calculated as cash provided by operating activities before settlement of asset retirement obligations and change in non-cash operating working capital.*

Celtic targets a net debt to trailing funds from operations ratio of less than 2.0 times. The Company manages its capital structure and makes adjustments according to market conditions in order to maintain flexibility to achieve its objectives stated above. To adjust its capital structure, the Company may increase or decrease capital expenditures, issue new shares, issue new debt or repay existing debt.

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital, excluding bank debt:

Twelve months ended December 31,	2009	2008
Accounts receivable	$ (11,756)	$ (42,963)
Drilling royalty credits	(13,159)	-
Prepaid expenses and deposits	(938)	(3,363)
Accounts payable and accruals	(2,839)	18,067
Change in non-cash working capital	$ (28,692)	$ (28,259)
Relating to:		
Operating activities	$ (13,261)	$ (41,300)
Investing activities	(15,431)	13,041
Change in non-cash working capital	$ (28,692)	$ (28,259)

During the reporting period, the Company made the following cash outlays in respect of interest expense:

Twelve months ended December 31,	2009	2008
Interest	$ 5,160	$ 6,355

12. RELATED–PARTY TRANSACTIONS

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the twelve months ended December 31, 2009, the Company incurred $0.3 million to BLG for legal fees and disbursements. These amounts have been recorded at the exchange amount. The Company expects to continue using the services of this law firm from time to time.

13. CONTINGENCIES

Celtic and SemCAMS are parties to a confidential KA Plant Inlet Gas Purchase Agreement (the "KA Plant Inlet Agreement"). The termination provision in the KA Plant Inlet Agreement requires that the terminating party provide the other party with two years written notice. SemCAMS entered into proceedings under CCAA on July 21, 2008, and to Celtic's knowledge, SemCAMS has not terminated the KA Plant Inlet Agreement in accordance with those proceedings or otherwise.

SemCAMS delivered a draft Agreement to Process Producers Gas at the KA Plant (the "Third-party Agreement") to Celtic under cover of a letter dated August 26, 2008, which purported to be effective July 22, 2008. However, Celtic never executed this agreement and gave immediate notice to SemCAMS that it did not agree to the terms contained in that agreement. Effective July 22, 2008, SemCAMS has continued to take deliveries of Celtic's natural gas with full knowledge that Celtic did not execute the Third-party Agreement. SemCAMS has invoiced Celtic for natural gas processing fees as set out in the un-executed Third-party Agreement. However, Celtic has been paying monthly processing fees as set out in the executed KA Plant Inlet Agreement. As at December 31, 2009, Celtic estimates that the difference in fees calculated under the Third-party Agreement compared to the KA Plant Inlet Agreement would result in an incremental expense to Celtic in the amount of $4.8 million.

14. SUBSEQUENT EVENT

In February 2010, Celtic announced that it had entered into an agreement to divest its interest in assets located at Swan Hills, Alberta. This transaction is effective February 1, 2010 and is expected to close on or about March 31, 2010. The Company expects to receive proceeds of $53.2 million, before closing adjustments. At December 31, 2009, proved reserves assigned to these assets were 1.1 million BOE and proved plus probable reserves were 2.0 million BOE. Production from these assets at the time of announcement was approximately 500 BOE per day.

CORPORATE INFORMATION

BOARD OF DIRECTORS

ROBERT J. DALES [2, 3, 4]
President, Valhalla Ventures Inc.

WILLIAM C. GUINAN [1, 5]
Partner, Borden Ladner Gervais LLP

ELDON A. MCINTYRE [2, 3, 4]
President, Jarrod Oils Ltd.

NEIL G. SINCLAIR [2, 4, 5]
President, Sinson Investments Ltd.

DAVID J. WILSON [3, 5]
President & Chief Executive Officer, Celtic Exploration Ltd.

OFFICERS

DAVID J. WILSON
President & Chief Executive Officer

SADIQ H. LALANI
Vice President, Finance & Chief Financial Officer

MICHAEL R. SHEA
Vice President, Land

DAVID C. MORGENSTERN
Vice President, Exploration

ALAN G. FRANKS
Vice President, Operations

[1] Chairman of the Board
[2] Member of the Audit Committee
[3] Member of the Reserves Committee
[4] Member of the Compensation Committee
[5] Member of the Disclosure Committee

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EVALUATION ENGINEERS

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STOCK EXCHANGE LISTING

TORONTO STOCK EXCHANGE
Trading symbol "CLT"

CELTIC'S ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

Celtic's Annual Meeting of shareholders will be held on Thursday, April 22, 2010 at 3:00 p.m. in the Grand Lecture Room at The Metropolitan Centre 333 – 4 Ave. S.W. Calgary, Alberta.

ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
BOE	barrels of oil equivalent
mBOE	thousand barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
MD&A	Management's Discussion and Analysis
GJ	gigajoules
T	tonnes
MT	thousand tonnes
AECO-C	Alberta Energy Company "C" Meter Station of the Nova Pipeline System
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
CICA	Canadian Institute of Chartered Accountants
BIT	before income taxes
WTI	West Texas Intermediate

CONVERSION OF UNITS

Imperial = Metric
1 acre = 0.4 hectares
2.5 acres = 1 hectare
1 bbl = 0.159 cubic metres
6.29 bbls = 1 cubic metre
1 foot = 0.3048 metres
3.281 feet = 1 metre
1 mcf = 28.2 cubic metres
0.035 mcf = 1 cubic metre
1 mile = 1.61 kilometres
0.62 miles = 1 kilometre
1 mmbtu = 1.054 GJ
0.949 mmbtu = 1 GJ

Natural gas is equated to oil on the basis of 6 mcf = 1 BOE.

Designed and produced by Foundry Creative Inc.

Celtic
EXPLORATION LTD.

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